AN EVALUATION OF PROCESSING OPTIONS FOR THE OIL SHALES OF ONTARIO

(UP-W-247)

Final Report

By

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Work on the project was conducted under the auspices of the Canada Centre for Mineral and Energy Technology, Energy, Mines and Resources Canada

248 pp

DSS File N°.: 15SQ.23440-49311
DSS Contract Serial N°.: 1SQ84-00374
CANMET Project N°.: 504604 (432553)
CANMET Scientific Authority: M. Skubnik

MAR 3 1988

MICROMEDIA

June 21, 1985

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CONVERSION FACTORS

SI UNITS		Multiply	TO OBTAIN	
Name	Symbol	By	Name	Symbol
Litres/tonne	L/t	0.240	US gallons/ton	US gal/ton
Cubic metres	m^3	6.290	Barrels	bbl
Tonne	t	1.102	Short tons	ton
Tonne	t	0.984	Long tons	long ton
Kilojoule/kilogram	kJ/kg	0.238	Calories/gram	cal/g
Megajoule/tonne	MJ/t	860	BTU/ton	BTU/ton
Megajoule/tonne	MJ/t	.251	Kilowatt hour/ton	kWh/ton
Kilopascal	kPa	0.145	Pounds/in^2	psig

1. SUMMARY

Watts, Griffis and McOuat Limited (WGM) reviewed available information on four oil shale-bearing formations from Ontario. The study included a development scenario based upon mining, processing and economic reviews. The highlight of the study was the discovery that using the appropriate technology a light petroleum oil, rich in middle distillates, could be obtained from Ontario oil shales.

Of the four different oil shales, those of the Kettle Point Formation, located near Sarnia, appear to have the best potential for development. In one hole, there is a 10 m section which contains 9.5 wt% organic carbon and yields 40 L/t (9.5 US gal/ton) by Fischer Assay. These yields can be more than doubled by retorting in the presence of hydrogen.

The mining review demonstrated that Ontario oil shales would most likely be exploited by open-cast rather than underground methods from both a technical and economic standpoint.

Process route selection studies determined that these oil shales could perhaps be exploited using the Conventional or Beneficiation routes. Processes that retort the oil shales in the presence of hydrogen have the most potential in terms of quantity and quality of oil and other end-products. Beneficiation of the shale prior to retorting appears technically feasible but requires further investigation before the economic benefits can be determined.

Preliminary capital and operating costs have been developed for a 30,000 ton/d (27,210 t/d) operation for two processes, and the economic analysis shows that an oil shale project located in Ontario could be financially attractive.

The study concludes that Ontario oil shales are a source of valuable hydrocarbons and require further investigation.

1. RÉSUMÉ

Watts, Griffis and McOuat Limited (WGM) a revu les informations disponibles sur quatre formations géologiques de l'Ontario contenant des schistes à kérogène. L'étude a incorporé un plan de développement basé sur une revue des méthodes d'exploitation et de traitement des schistes et de données économiques. Un point important de l'étude a été la réalisation qu'une technologie appropriée produirait un mazout léger, riche en distillats intermédiaires, à partir de ces schistes à kérogène de l'Ontario.

Des quatres schistes à kérogène, la Formation de Kettle Point, située près de Sarnia, paraît avoir le meilleur potentiel de développement. Dans un sondage, le schiste à kérogène a une intersection d'une puissance de 10 mètres contenant 9.5 pour cent en carbone organique et produit 40 litres à la tonne (9.5 US gal/ton) de mazout par pyrolyse. Ce rendement peut être doublé par pyrolyse en présence d'hydrogène gazeux.

L'étude des méthodes d'exploitation minière a démontré que les schistes à kérogène de l'Ontario devraient être exploité en carrière plutôt qu'en souterrain, tant du point de vue technique qu'économique.

Les études portant sur la sélection des méthodes de traitement ont démontré que ces schistes à kérogène pourraient être traités soit par les méthodes "Conventional" ou par "Beneficiation". Les procédés qui pyrolysent les schistes à kérogène en présence d'hydrogène gazeux ont le plus de potentiel en regard de la quantité et de la qualité de mazout et autres produits dégagés. L'enrichissement de la teneur en kérogène, avant la pyrolyse, apparaît techniquement faisable mais requiert une étude plus poussée pour que les avantages économiques puissent être déterminés.

Les coûts d'investissement et opératoires ont été estimés de façon préliminaire pour deux procédés traitant 27,210 tonnes (30 000 tons) de schiste par jour et les résultats de l'évaluation économique ont démontré qu'une usine de schistes à kérogène installée dans la province de l'Ontario pourrait être financièrement rentable.

La conclusion de l'étude est que les schistes à kérogène représentent un potentiel valable de réserves en hydrocarbures et qu'il est indiqué de poursuivre les recherches.

2. INTRODUCTION

2.1 BACKGROUND TO REPORT

In 1983, the Ontario Ministry of Energy (OME 1983a, p. 6) reported that the Province of Ontario consumes one-third of Canada's energy and, of this total energy requirement, about 75% has to be obtained from outside the province. The impact on Ontario's economy is indicated by the fact that in 1982 its refineries and utilities spent approximately $9 billion for crude oil and natural gas obtained from outside the province. Clearly, the economic benefits to Ontario of having its own secure supply of liquid fuels would be enormous.

This point has not been lost on the government of Ontario. In October 1980, it introduced a long-term strategy to help the province become more energy efficient and less dependent on oil, and also set a goal to increase the amount of energy produced from indigenous sources (23% in 1979). Even earlier, in late 1979, the Ontario Geological Survey (OGS) of the Ministry of Natural Resources (MNR) was given a mandate to carry out an inventory of the province's hydrocarbon energy resources and to determine the contribution that these could make to greater energy self-sufficiency. This led to the development and initiation in 1981 of the Hydrocarbon Energy Resources Program (HERP). HERP consists of four major components, one of which is the Oil Shale Assessment Project. The work being done by OGS under the Oil Shale Assessment Program is strictly a comprehensive geological characterization of the shales in Ontario, and does not attempt either to identify or to develop process technology applicable to these shales. The program is expected to continue until 1986.

In August 1984, Watts, Griffis and McOuat Limited (WGM) submitted an unsolicited proposal to the Canada Centre for Minerals and Energy Technology (CANMET) suggesting that a research project be undertaken on Ontario oil shales. CANMET expressed interest in the proposal and, following a series of discussions with WGM, awarded an assignment for an evaluation of processing options for the oil shales of Ontario. WGM commenced work on the project early in 1985. The evaluation,

presented in this report, includes: characterization of four oil shale formations of Ontario, mining and processing studies, anticipated environmental effects of an oil shale industry, and a brief and preliminary economic assessment.

WGM is uniquely qualified to undertake this study for CANMET because of previous experience with oil shale programs in Ontario. In 1973, WGM conducted an in-house literature search to determine the extent of oil shale deposits in Alaska and Canada. In subsequent years, we continued to monitor developments relating to oil shales in Canada and elsewhere, and compiled a data file of published material on oil-shale projects and research and development in process technology. In 1979 and 1981, WGM undertook two studies on behalf of a private client and in 1983, for the OME, we completed Phase I of a proposed long-range, four-phase program to develop a treatment process for Ontario's oil shales.

2.2 UNITS

Throughout this report we have tried wherever practical to express all units of measurement in terms of the SI system. It should be noted, however, that the bulk of the research work which is applicable to this study has been completed in the United States. We have therefore, in many cases, included such measurements as US gallons per ton in parentheses after the relevant SI measurements. Furthermore, we believe that the results of our economic analysis will be more meaningful to the average reader as they are presented, in terms of US $ per barrel rather than in C $ per m^3.

For convenience we have provided some of the less common units and symbols of the SI system below together with conversion factors to other units.

SI UNITS		Multiply	TO OBTAIN	
Name	Symbol	By	Name	Symbol
Litres/tonne	L/t	0.240	US gallons/ton	US gal/ton
Cubic metres	m^3	6.290	Barrels	bbl
Tonne	t	1.102	Short tons	ton
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Megajoule/tonne	MJ/t	860	BTU/ton	BTU/ton
Megajoule/tonne	MJ/t	0.251	Kilowatt hour/ton	kWh/ton
Kilopascal	kPa	0.145	Pounds/in^2	psig

2.3 ENERGY SUPPLY REVIEW

2.3.1 GENERAL

The province of Ontario consumes one-third of Canada's energy; of this total requirement, about 75% is obtained from outside the province and, in 1982, the cost to Ontario's refineries and utilities for crude oil and natural gas obtained from outside was $9 billion. In this section, Ontario's energy requirements are examined in more detail, particularly with regard to liquid fuels, in order to illustrate the importance to the province of the potential contribution from its oil shale resources. In addition, changing trends in energy consumption are examined.

Crude oil meets approximately 35% of Ontario's primary energy needs, natural gas 23%, coal 16%, uranium 13%, and hydroelectric power 12%. Primary energy relates to the energy contained in such sources as crude oil, natural gas, coal, hydroelectric power, and uranium. Much of this energy is converted to secondary fuels (or secondary energy). For instance, crude oil is a form of primary energy, which is converted to such secondary energy fuels as heating oil and gasoline. Canada's total energy picture is somewhat different: crude oil meets about 37% of Canada's needs, natural gas 19% and coal 10%. Hydroelectric power provides about one-quarter of Canada's energy requirements; twice the proportion for Ontario. Although uranium is a major source of energy in Ontario, its Canada-wide share is only about 5%. Most of the uranium consumed in Canada is used to generate electricity in Ontario.

Canada's and Ontario's consumption of energy, by category, is summarized and compared in the following table.

TABLE 2-1

PRIMARY ENERGY USE

Source	Ontario (%)	Canada (%)
Wood Waste	1.7	3.0
Uranium	13.2	4.7
Hydroelectric Power	12.4	25.6
Coal	15.5	10.1
Natural Gas	22.6	19.4
Crude Oil	34.6	37.2

2.3.2 OIL SUPPLY AND DEMAND: CANADA AND ONTARIO

2.3.2.1 Canada

In 1982, Canada's oil requirements were about 250,000 m^3 (1,573,000 bbl) per day. Net imports amounted to about 8% of these requirements or about 20,000 m^3 (126,000 bbl) per day. Between 1980 and 1982, Canada's oil consumption dropped 16%, and demand is expected to decline about 1% per year between 1982 and 1990, according to projections made by the federal government in mid-1982.

As for supply, Canada's conventional oil reserves, located primarily in western Canada, continue to decline. At the end of 1981, Canada had economically recoverable reserves of 715 million m^3, or 4.5 billion bbl, of conventional oil (OME 1983; NEB 1984). This represents about a ten-year supply, based on 1982 production levels.

New discoveries of oil in western Canada and improved techniques for extraction from known reservoirs are expected to increase the availability of oil in the future. Canada also has vast resources in the oil sands regions of western Canada and in the frontier areas. Only Hibernia, off the coast of Newfoundland, has been developed to the point where production can be expected by 1990.

The Alberta Energy Resources Conservation Board (AERCB) estimated that, at the end of 1981, 3.9 billion m^3 (24.5 billion bbl) of synthetic crude oil could be recovered by surface mining from established reserves in the oil sands regions. However, the

AERCB also pointed out that the long-term optimism for bitumen production and synthetic crude oil supply is contingent on development of suitable fiscal regimes that would provide a satisfactory economic basis for the construction and operation of upgrading facilities.

2.3.2.2 Ontario

Oil consumption in Ontario in 1982 was 77,960 m^3 (about 490,000 bbl) of oil per day. Over 90% of the oil Ontario consumes comes from western Canada via the Interprovincial Pipeline system. Most of the rest is U.S. crude oil obtained on an exchange basis to reduce east–west transportation costs.

The demand for oil in Ontario has been cut by a significant amount in recent years. Between 1979 and 1981, for example, Ontario's oil consumption dropped about 10%. This decline was slightly more than the 9% reduction for Canada as a whole and well above the 7% drop in world demand. During 1982, Ontario's estimated oil consumption declined a further 11%.

Between 1975 and 1982, oil's share of Ontario's primary energy use fell from 40% to 35%. Despite this drop, oil remains the single most important source of energy in Ontario.

Ontario produces about three-tenths of one percent of the oil it consumes; that is, about 160 m^3 (about 1,000 bbl) of oil per day. The Ontario Energy Corporation (OEC) is exploring for oil and gas near Sarnia in southwestern Ontario; it was in this area near Oil Springs, that the first commercial oil well in North America was established in 1858. Also, as noted above, the OEC and the MNR are investigating these deposits to determine whether the oil can be recovered economically.

2.3.3 PROJECTIONS OF OIL SUPPLY AND DEMAND TO THE YEAR 2005

2.3.3.1 Canada

Productive capacity from established Canadian reserves of conventional crude oil is expected to decline from a level of 200,000 m^3 (1,258,000 bbl) per day in 1983 to a

level of 19,000 m^3 (120,000 bbl) per day in 2005, or about 10% of the current level. This decline will be partially offset by anticipated reserve additions during the same period, consisting of:

(1) future discoveries and appreciation of reserves in established pools; and

(2) enhanced recovery of currently established reserves.

The National Energy Board of Canada (NEB 1984, p. 71–75) has estimated that reserve additions in established producing areas for the period 1983–2005 will be 678 million m^3 (4.3 billion bbl), as shown in Table 2-2.

TABLE 2-2

ADDITIONS TO CANADA'S RESERVES OF CONVENTIONAL CRUDE OIL IN ESTABLISHED PRODUCING AREAS

Description	Light m^3 ($\times 10^6$)	Heavy m^3 ($\times 10^6$)	Total m^3 ($\times 10^6$)	Light bbl ($\times 10^6$)	Heavy bbl ($\times 10^6$)	Total bbl ($\times 10^6$)
Future discoveries; appreciation in established pools	229	87	316	1,440	547	1,987
Enhanced recovery of established reserves	228	134	362	1,434	843	2,277
Total	457	221	678	2,874	1,390	4,264

The NEB's forecast, for the supply that will be derived from oil sands, is that:

1. In-situ production of crude bitumen will grow from the current level of 5,000 m^3 (31,450 bbl) per day to 35,000 m^3 (220,150 bbl) per day in 2005.
2. With regard to oil sands mining, it is assumed that one plant will come on stream in 1992 and another in 1999, both at a capacity of 10,000 m^3 (62,900 bbl) per day.

Forecasting the supply from the three frontier areas currently being explored — the Beaufort Sea, Mackenzie Delta, the Arctic Islands and the east coast offshore

area — proved to be a difficult proposition. The NEB (1984, p. 78) concluded that the supply could range anywhere from zero to 200,000 m^3 (1,258,000 bbl) per day in 2005 and that the degree of success achieved in developing production from frontier regions will be an important factor in determining how rapidly synthetic fuels projects proceed.

Finally, based on estimates by submittors to the NEB's 1984 technical report on Canadian energy supply and demand, the total supply of crude oil and equivalent in 2005 could range from 110,000 to 270,000 m^3 (692,000 to 1.7 million bbl) per day. As far as the supply/demand balance in terms of light and heavy crude oil is concerned, a persistent excess of demand over supply of up to 33,000 m^3 (208,000 bbl) per day is indicated, except for a short period immediately following the introduction of frontier production in 1993. The difference between total supply and total demand represents the implied net import requirement for light crude oil.

2.3.3.2 Ontario

The NEB's estimated that Ontario's recoverable reserves of conventional crude oil at the end of 1983 were 534,000 m^3 or 3.36 million bbl. The productive capacity of Ontario sources is forecast to decline gradually from 218 m^3 (1,371 bbl) per day in 1983, to 76 m^3 (478 bbl) per day in 1990, 36 m^3 (226 bbl) per day in 1995, and to 0 by the year 2005.

According to the OME (1983a, p. 49), the Ontario government has set oil substitution and energy conservation targets for each sector of the economy. If these targets are reached, the increase in total energy used by the transportation, residential, commercial and industrial sectors would average only 1% annually, less than half the 2.5% annual growth experienced from 1970 to 1980.

The transportation sector, which depends almost entirely on refined petroleum products, consumes about half the oil used in Ontario. However, between 1973 and 1982, gasoline consumption per household in Ontario declined 25%. One of the conservation targets set by the Ontario government for this sector is to reduce oil's

share in the transportation sector to 90% by 1995. This calls for greater use of fuels such as propane, compressed natural gas and methanol.

The OME stated (1983a, p. 61) that significant dependence on oil continues to be Canada's and Ontario's major energy problem and, since Ontario consumes about one-third of all the oil needed in Canada, the province can play a crucial role in helping the country reach oil self-sufficiency.

The OME (1983a, p. 60) has predicted that by the year 2000, Ontario will likely consume 10% less oil than at present, but will still require about 30 million m^3 (189 million bbl) of this fuel annually. Nearly 75% of this total might be required for transportation and petrochemical uses.

Also (OME 1983a, p. 60):

> *Ontario supports the national goal of self-sufficiency in oil by 1990. The prospects for additional domestic supply suggest, however, that this objective will require a rapid reduction in the demand for oil through stronger conservation and substitution initiatives in the next few years.*

The goal of the Ontario government is to produce 35% of its energy from sources within Ontario by 1995 (OME 1979). The existence of the HERP program is a clear indication that the Government of Ontario recognizes that the development of Ontario oil shales could be a factor in achieving this target.

3. CHARACTERIZATION OF ONTARIO OIL SHALES

3.1 DEFINITIONS AND ANALYTICAL METHODS

In the Glossary of Geology (American Geological Institute 1980), oil shale is defined as:

> *. . . a kerogen-bearing, finely laminated brown or black sedimentary rock that will yield liquid or gaseous hydrocarbons on distillation . . .;*

and kerogen is defined as:

> *. . . fossilized insoluble organic material found in sedimentary rocks, usually shales, which can be converted by distillation to petroleum products.*

Macauley's (1984) definition is similar, that is:

> *Oil shale is a fine-grained sedimentary rock, containing indigenous organic matter, mostly insoluble in ordinary petroleum solvents, from which significant amounts of shale oil can be extracted by pyrolysis (i.e., heating in a retort).*

Macauley also attempted to further define what he meant by "significant amounts": the minimum organic content at which the amount of heat recovered as shale oil could theoretically balance the input heat is 2.5%. This does not allow (he said) for other energy-equivalent input (mining, transportation, etc.); therefore, a lower limit of 5% organic content (i.e., 25 L/t, or 6 US gal/ton) is frequently used.

In this report, an oil shale is required to yield, by pyrolysis, 2% hydrocarbons, equivalent to 20–22 L/t, or 4.8–5.3 US gal/ton.

Pyrolysis is the destructive distillation of a compound at temperatures ranging from 500°C to 600°C. It takes about 1,050 kJ/kg (250 cal/g) to raise the temperature of a rock fragment from ambient temperature to 500°C. The calorific value of organic material averages 42,000 kJ/kg (10,000 cal/g), so that at least 2.5% by weight of organic material is necessary to counterbalance the energy required to heat the rock.

Since other forms of energy would be needed to mine, transport and process shale prior to, during or after retorting, it is generally accepted that a 5% organic matter content is the lower limit in terms of 'significant amounts' necessary to define a kerogen-rich rock as an exploitable 'oil shale'.

Shale oil is produced from oil shale by pyrolysis of the kerogen and is a mixture of hydrocarbons formed at temperatures between 200° and 600°C. The composition of shale oil is dependent on the kerogen present and is invariably represented by hydrogen-poor hydrocarbon products. Prior to its processing in refineries geared for conventional crude from oil reservoirs, shale oil requires upgrading by hydrogenation by methods similar to those used with heavy syncrude from tar sands.

Several analytical techniques are employed in characterization of oil shales:

1. Total Organic Carbon (**TOC**)
2. Total Inorganic Carbon (**TIC**)
3. Hydrogen/Carbon Ratio (**H : C**) of kerogen
4. Yield on Pyrolysis (**YP**)
5. Fischer Assay (**FA**) (ASTM Designation: D3904-80)
6. Hydrogen Retorting

The following descriptions of these analytical techniques are adapted from Barker et al. (1983) with some comments by WGM:

Total Organic Carbon

Pulverized samples (< -150 µm) are leached of inorganic carbon with hot 6 M HCl. The samples are then rapidly heated to more than 1,000°C in an oxygen stream in an induction furnace. The available carbon is completely oxidized to carbon dioxide. The amount of carbon dioxide is then measured by a non-dispersive infrared analyzer and displayed as a sharp peak on an integrating recorder. The system is calibrated by calcining $CaCO_3$ standards.

TOC measurements indicate how much organic matter is present in the sample. It does not indicate the nature of this organic matter. Kerogen, the dominant form of dispersed organic matter in rock, is 79% carbon on average (Hunt 1979).

Total Inorganic Carbon

TIC values are obtained by subtracting the TOC values from total carbon values. The total carbon method is identical to the TOC procedure, except that the carbonates are not acid leached from the sample. In other words, the raw shale is combusted directly.

TIC is a measure of the content of carbonate minerals in the rock. The most common carbonates are calcite ($CaCO_3$), dolomite ($Ca, Mg(CO_3)_2$), and occasionally siderite ($FeCO_3$).

Hydrogen/Carbon Ratio of Kerogen

Solvent extracted kerogen is treated with 20% HCl and 50% HF to remove any mineral matter attached to the kerogen. The kerogen is then washed repeatedly with deionized water to neutralize the pH and dried.

The kerogen is oven dried and combusted. The evolved hydrogen and carbon are measured. The quantities are expressed as weight percent, which are then converted to atomic ratios.

The H : C elemental ratio is useful in "typing" a kerogen as Type I, II or III (Hunt 1979 and others). Also, the yield of hydrocarbons from Fischer Assay appears to be limited by the hydrogen content of the kerogen and so samples of highest H : C are expected to yield the most hydrocarbons per unit carbon content.

Yield on Pyrolysis

A known quantity of raw shale (approximately 5–10 mg) is rapidly heated in a helium stream to a temperature in excess of 600°C. The hydrocarbons that are produced are measured with a flame ionization detector. Methane injections are used for calibration. The results are expressed as weight percent methane equivalents. These methane equivalents are divided by the ratio of the molar weights of methane or carbon (1.34) and final results are reported as weight percent carbon (methane equivalent).

Caution should be exercised when extrapolating these yields to expected process yields. In an actual retorting process, it is unlikely that the oil shale would be subjected to such rapid heating rates. This subject is discussed in more detail in Section 5.2.

Fischer Assay

Crushed raw shale is composited by riffle splitting. The determination of the oil yield from oil shale is made by heating 100 g of raw shale from ambient temperature to 500°C in cast aluminum-alloy retorts. The vapours distilled from the sample are cooled and the condensed fraction is collected. The products of this condensation can be calculated to indicate the yields of water, oil and gas per tonnes of shale.

The FA is the industry standard for evaluating the yield of oil from shales during pyrolysis and in fact process yields are usually compared to FA. Commercial operations could obtain considerably different results, however, and these can be sometimes higher than FA. FA is essentially a bench-scale apparatus that simulates a particular process. The FA retort is described in more detail in Section 6.2.2.

Hydrogen Retorting Assay

Hydrogen retorting assay is a laboratory simulation of the HYTORT process, developed by HYCRUDE Corporation of Chicago, Illinois. The process which is specifically designed for oil shales with a low H : C atomic ratio is described in detail in Section 6.4.6.

HYCRUDE has constructed a computerized Hydroretorting Assay Unit in which a small sample of oil shale is reacted under precisely controlled conditions of pressure, temperature and residence time in a hydrogen atmosphere. The resulting oil yield indicates the potential HYTORT oil yield for the shale and demonstrates the improvement possible over conventional retorting (HYCRUDE 1984).

3.2 GENERAL GEOLOGY OF ONTARIO OIL SHALES

Four Paleozoic formations containing oil shales are known to exist in Ontario. These occur in two physiographic regions, the Great Lakes Lowland and the Hudson Platform.

The Great Lakes Lowland is bounded to the south and west by Lakes Ontario, Erie and Huron, and to the north by the Precambrian Shield. The surface topography of the area appears flat. Thick glacial overburden (up to 180 m) blankets the area, masking any relationship between the present surface and the structure of the underlying bedrock. Regionally, however, there is considerable variation in relief. The land rises from an elevation of 174 m at Lake Erie to about 520 m in the region south of Georgian Bay, and then decreases to 177 m along the shore of Lake Huron. This regional variation is due to a Precambrian basement high known as the Algonquin Arch, which separates the Michigan Basin to the northwest from the Appalachian geosyncline to the southeast. The arch is probably at the same elevation now as it was during Late Cambrian time, when the first Paleozoic seas transgressed the region — although it is known to have fluctuated upward and downward at various intervals during the Paleozoic (Sanford 1968).

Similar structures existed to the south in the United States (Figure 3-1). The Cincinnati Arch trends north from Tennessee through Kentucky and into Indiana and Ohio, separating the Illinois Basin from the Appalachian geosyncline. At this point, it appears to divide. One projection (sometimes known as the Kankakee Arch) extends

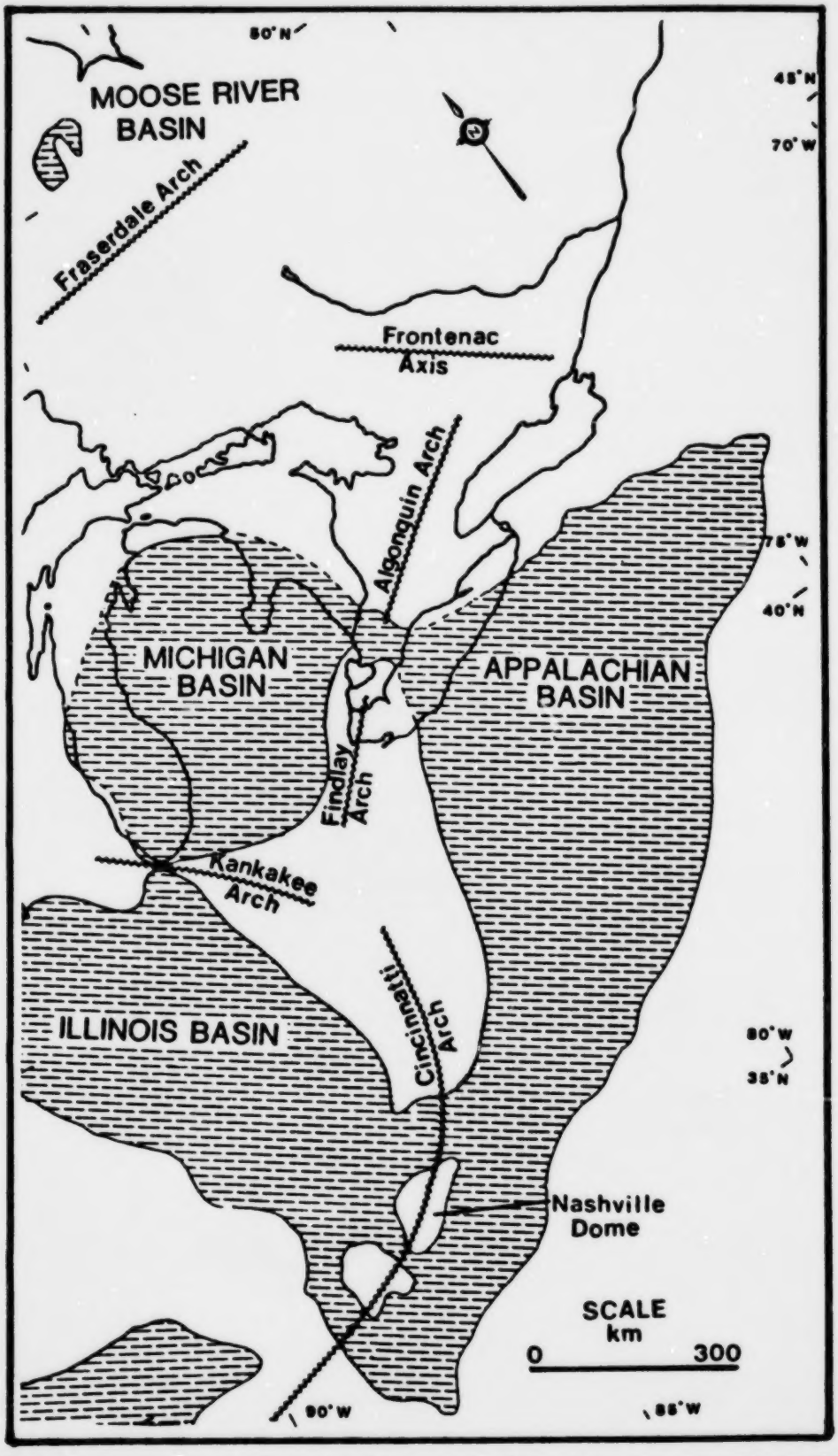

FIGURE 3-1: The extent of Devonian black shale deposition in eastern North America showing major tectonic features (adapted from Telford 1984).

northwest through Illinois and Wisconsin, separating the Illinois Basin from the Michigan Basin. The other projection, the Findlay Arch, extends northeast through Ohio to Ontario, where it terminates close to the Algonquin Arch. All of these structures are probably interrelated, although they are known to have moved independently of one another at various times.

For much of Paleozoic time, the Great Lakes Lowland was covered by shallow marine seas; and at least four times during that period, conditions were favourable for the wide-scale deposition of organic-rich sediments — the precursor of organic-rich sedimentary rocks. These rocks are represented by the Upper Ordovician Collingwood Formation, the Middle Devonian Marcellus Formation, and the Upper Devonian Kettle Point Formation (see Figure 3-2).

The Hudson Platform lies within the central part of the Canadian Shield and contains the Moose River and Hudson Bay sedimentary basins. The Moose River Basin includes the Mesozoic and Paleozoic sedimentary rocks underlying James Bay, as well as the land area drained by the Moose, Albany and Attawapiskat Rivers to the southwest (the James Bay Lowland). The northeast-trending Cape Henrietta Maria Arch separates the Moose River Basin from the Hudson Bay Basin to the north.

The Paleozoic sequence of the Moose River Basin consists of a thickness of about 700 m of Ordovician, Silurian and Devonian strata. These consist principally of marine carbonate rocks, shales, evaporites, and minor marine and continental clastic sediments. Of interest for this study is the Long Rapids Formation of Upper Devonian age: a sequence of black shales and siltstones interbedded with grey-green clays. This formation is age-equivalent to the Kettle Point Formation of southwestern Ontario and also to the Ohio – Chattanooga – New Albany – Antrim shales of the eastern United States (Sanford and Norris 1975).

Macauley completed a review of the geology of Canadian oil shale deposits for the Geological Survey of Canada (GSC) in 1984.

In his description of the 18 principal oil shale deposits of Canada, Macauley included five areas in Ontario. In two of these areas the strata are of Ordovician age; in the other three areas they are of Devonian age, as follows:

Ordovician

(1) *Manitoulin–Collingwood trend: Collingwood shale outcropping parallel to the base of the Niagara Escarpment; thin, widespread, black shale deposited between carbonate zones on a shallow marine platform.*

Devonian

(1) *Elgin and Norfolk Counties, north shore of Lake Erie: Marcellus, a thin Middle Devonian organic shale overlying carbonate and deposited on a marine platform;*

(2) *southwestern Ontario, Windsor–Sarnia area: Kettle Point Formation, Upper Devonian; up to 30 m black oil shale; and*

(3) *Moose River Basin, Hudson Bay Lowland: Long Rapids Formation, Upper Devonian; geologically equivalent and comparable to Kettle Point Formation of Windsor–Sarnia area.*

A fifth formation was identified in the Ottawa area, but from the results of OGS studies and according to the WGM definition (Section 3.1), yields from this shale would be too low to rate classification as oil shale.

The OGS initiated an Oil Shale Assessment Program in 1981. Drilling initially was undertaken on the Collingwood Member of the Lindsay Formation. Later, in 1982, the Kettle Point and Marcellus Formations were also drilled. All of these drill holes were cored throughout their entire length and down-the-hole geophysical logs (gamma, density, neutron, focussed electric and sonic) were undertaken. Core samples were subjected to organic geochemical analyses (total organic carbon content, yield on pyrolysis and Fischer Assay yield). Mineralogical studies were also completed and the physical properties of the shales were tested. Results of analyses from the Kettle Point were very encouraging, while those from the Marcellus were less so. The analytical results and their implications for each of the units are discussed in the remaining sections of this chapter, together with discussions of the stratigraphy and lithology, and investigations completed.

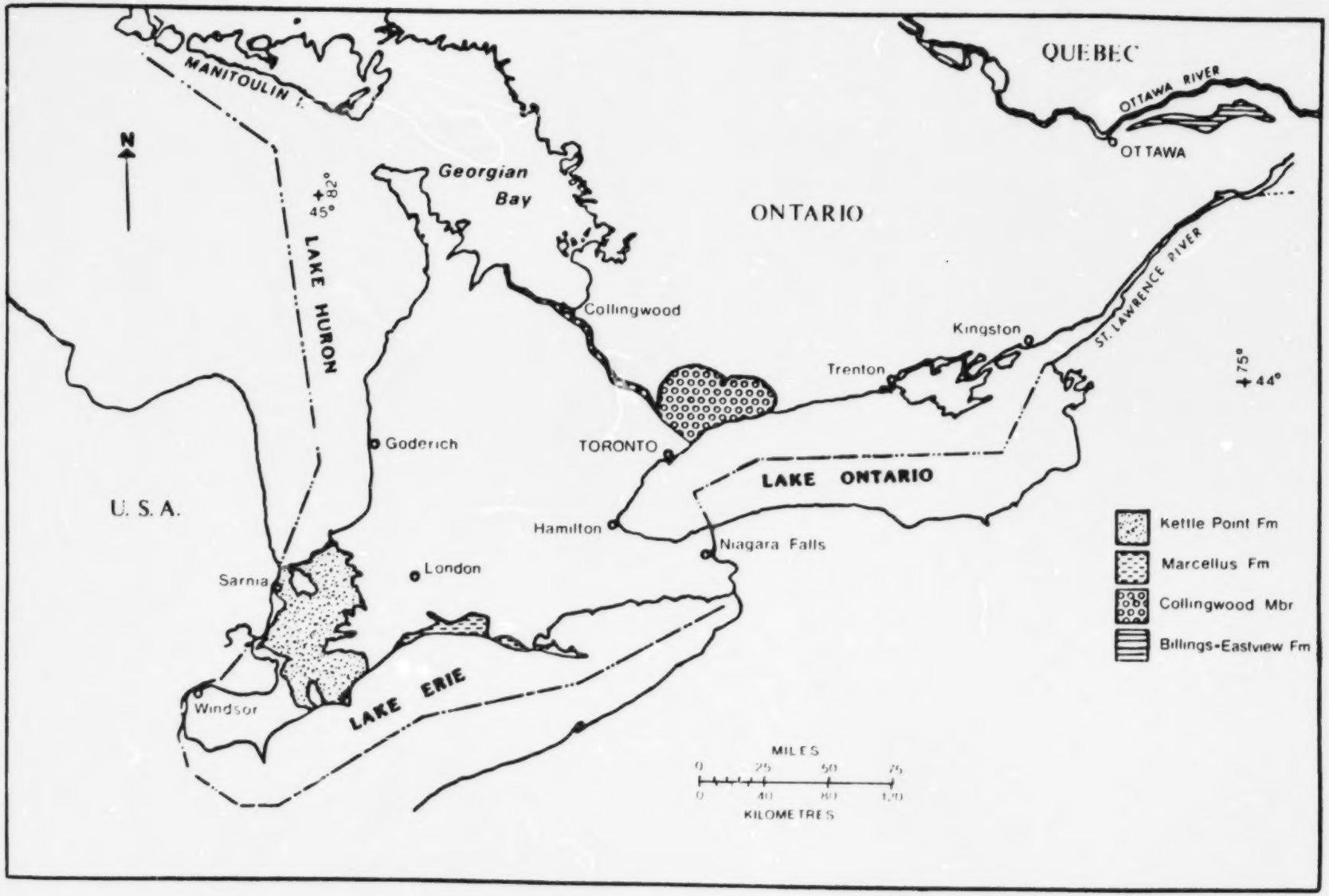

FIGURE 3-2: Distribution of oil shales in southern Ontario (source: Telford 1984).

3.3 THE KETTLE POINT FORMATION

3.3.1 GENERAL

The Kettle Point Formation underlies a large area of southwestern Ontario, outcropping and subcropping in a broad band from southern Lake Huron and the Sarnia region to the Port Alma area on Lake Erie. It is named from the location of its only substantial outcrop, on the shore of Lake Huron at Kettle Point, where the characteristic nodules of the lower part of the formation are locally called 'kettles' (Russell and Barker 1983, p. 170).

The Kettle Point Formation is the lithologic and stratigraphic equivalent of an Upper Devonian black shale sequence that extends to the west into Michigan and to the south through Ohio, Indiana, Kentucky, Tennessee to Alabama. These shales are known by various names (Antrim, Ohio, New Albany, and Chattanooga), but are all very similar lithologically. In the Moose River Basin, the Long Rapids Formation, which is described in Section 3.4, represents the northernmost extent of Upper Devonian black shale deposition.

3.3.2 INVESTIGATIONS BY THE OGS

Because of the almost complete lack of outcrop, the OGS completed two deep holes and a grid of 20 shallow drill holes in the subcrop area of the Kettle Point Formation, in 1982. The shallow holes were terminated at the base of the Kettle Point Formation; the two deep holes were continued into the Precambrian basement. The results are summarized in Table 3-1.

3.3.3 THICKNESS AND LITHOLOGY

According to Telford (1984, p. 6), the Kettle Point Formation has a maximum thickness of 60 m. However, the average thickness across the subcrop area is only about 28 m and it is likely that a considerable amount of the unit has been removed by post-Devonian erosion. In some locations, the Kettle Point Formation is overlain by

TABLE 3 - 1

KETTLE POINT FORMATION: SUMMARY OF OGS RESULTS

HOLE	INTERCEPTS			TOTAL ORGANIC CARBON (wt%)	PYRO-PROBE YIELD (wt%)[1]	FISCHER ASSAY		
	FROM (m)	TO (m)	LENGTH (m)			OIL YIELD		GAS + LOSS (wt%)
						US gal/ton	wt%	
KP-10	32.19	44.45	12.26	7.67	2.10	9.20	3.90	1.30
-11	26.60	53.53	26.93	5.28	1.00	4.40	1.70	1.00
-12	23.51	34.85	11.34	6.17	1.20	6.90	2.70	1.40
-13	27.92	41.03	13.11	6.55	1.40	5.20	2.00	1.00
-14	22.57	26.22	3.65	7.85	1.80	9.10	3.60	2.20
	26.22	31.92	5.70	6.14	1.10	5.30	2.10	—
	31.92	36.70	4.78	2.49	.50	2.60	1.00	.60
	36.70	42.70	6.00	6.53	1.70	8.35	3.20	.90
	42.70	48.39	5.69	1.45	.80	3.70	1.40	1.40
	48.39	53.30	4.91	4.24	1.20	4.50	1.80	—
	53.30	54.70	1.40	7.95	2.30	—	—	—
-15	11.15	20.32	9.17	5.58	1.80	8.70	3.40	1.60
	20.32	26.90	6.58	3.63	1.65	7.00	2.70	.90
	26.90	32.20	5.30	5.33	1.50	6.40	2.50	1.50
	32.20	36.82	4.62	8.90	2.20	10.50	4.10	.90
	36.82	49.60	12.78	4.80	1.60	6.70	2.60	1.80
	49.60	59.69	10.09	9.42	1.70	7.90	3.10	1.20
-16	21.34	30.43	9.09	6.97	1.60	6.60	2.50	.80
	30.43	51.34	20.91	3.45	.90	3.60	1.36	.50
	51.34	74.84	23.50	5.67	1.70	7.10	2.70	1.40
	74.84	88.34	13.50	6.20	1.10	7.30	2.80	1.50
-17	37.45	39.92	2.47	8.70	1.70	—	—	—
	39.92	56.71	16.79	1.56	.10	1.90	.70	.90
	56.71	94.92	38.21	6.12	1.40	6.31	2.33	1.14
-18	42.70	57.08	14.38	7.90	1.80	7.80	3.00	1.00
	57.08	62.35	5.27	5.78	1.20	4.10	1.60	1.20
	62.35	67.58	5.23	.55	—	1.80	.70	—
	67.58	73.50	5.92	5.90	1.30	5.20	2.00	.70
	73.50	79.59	6.09	4.37	1.50	5.90	2.30	.60
	79.59	93.79	14.20	5.95	1.60	7.00	2.70	1.20
	93.79	104.84	11.05	8.77	2.10	7.20	2.80	1.50
	104.84	108.39	3.55	5.40	—	—	—	—
-19	45.72	83.65	37.93	6.48	1.30	6.40	2.50	.80
-20	13.00	22.49	9.49	7.10	1.20	5.80	2.20	.40
-21	—	—	—	—	—	—	—	—
-22	3.16	11.61	8.45	.66	—	<1.00	—	—
	11.61	14.92	3.31	6.47	1.00	6.10	2.30	1.10
	14.92	16.26	1.34	9.32	1.30	9.60	3.70	1.40
	16.26	25.47	9.21	6.51	.20	7.10	2.80	1.40
	25.47	26.02	.55	3.87	—	4.60	1.80	1.00
-23	16.74	20.12	3.38	3.20	—	—	—	—
	20.12	23.73	3.61	6.05	1.40	6.10	2.40	2.00
	23.73	26.00	2.27	1.98	.60	2.60	1.00	1.20
	26.00	40.25	14.25	6.53	1.50	7.00	2.70	1.30
-24	47.82	51.85	4.03	12.59	3.30	12.90	5.10	2.30
	51.85	61.22	9.37	8.15	2.10	9.00	3.50	1.30
	61.22	86.72	25.50	6.04	1.50	7.15	2.70	1.30
	86.72	89.27	2.55	6.59	1.90	8.50	3.30	.20
	89.27	94.06	4.79	7.70	2.00	9.60	3.80	.20
	94.06	103.14	9.08	6.16	1.90	7.60	3.00	1.40
	103.14	106.50	3.36	7.82	1.70	8.60	3.40	1.30
	106.50	111.74	5.24	6.03	1.70	7.60	3.00	1.20
	111.74	118.83	7.09	8.14	2.30	10.20	4.00	1.60
	118.83	124.44	5.61	4.03	—	—	—	.30
-25	33.56	44.21	10.65	8.18	2.10	7.40	2.90	.90
	44.21	93.14	48.93	6.16	1.70	6.40	2.50	1.50
-26	32.05	55.18	23.13	6.92	1.70	7.20	2.80	1.00
-27	10.67	12.50	1.83	9.35	—	—	—	—
	12.50	32.92	20.42	6.76	1.60	7.20	2.80	1.00
-28	13.37	14.26	.89	3.40	—	—	—	—
	14.26	28.96	14.70	6.68	1.50	5.40	2.13	.80
	28.96	32.91	3.95	2.30	—	—	—	—

[1]wt% carbon (methane equivalent).

units of the Port Lambton Group. The formation is relatively thin in these areas, but biostratigraphic studies (Uyeno et al. 1982) suggest that the accumulated strata represent much of Upper Devonian time.

Telford (1984, p. 6) reported that the Kettle Point Formation consists of dark grey, brown-grey to black, silty argillaceous shale. It is generally non-calcareous, except for large concretions (up to 1 m in diameter) near the base, of the type section. In the southern and central parts of the subcrop belt, several zones of green laminated and/or bioturbated shale interbeds are present in the lower half of the formation. In another zone, the black shales contain numerous thin white-quartz silt bands.

3.3.4 STRATIGRAPHY AND STRUCTURE

The Kettle Point Formation is either flat-lying or dips gently from the Algonquin Arch into the Michigan Basin to the northwest, and the Appalachian Basin to the southeast. To the northwest, the black and green shales of the Kettle Point Formation can be correlated easily with subunits 1 through 6 of the Antrim shale of the Michigan Basin (Figure 3-4). To the southeast, the shales can be equally correlated with units of the Ohio shale in the Appalachian Basin. Russell (1984) has described the stratigraphy of the Kettle Point Formation and the reader is referred to this excellent paper for further detail. The subcrop area of the Kettle Point is shown in Figure 3-3. It disconformably overlies shales and limestones of the Hamilton Group.

3.3.5 GEOCHEMISTRY

The primary indicator of the oil shale potential of an organic shale is the total organic carbon (TOC) content. According to Russell and Barker (1983, p. 176), many hundreds of samples from the Kettle Point Formation have been processed for TOC and these data will provide one basis for regional evaluation of the resource potential of the Kettle Point Formation.

The KP-24 drill hole intersected the entire succession of the Kettle Point Formation and has been the most intensely studied. The Antrim shale of the Michigan Basin has

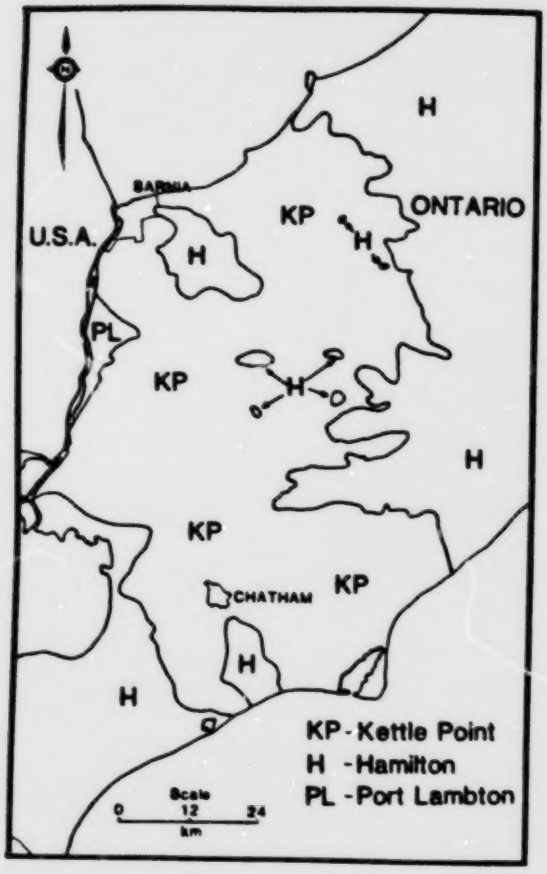

FIGURE 3-3: Subcrop area of Kettle Point Formation, southwestern Ontario (source: Russell and Barker 1983).

been divided into six subunits on the basis of gamma ray logs: these can be traced across the Michigan Basin and all six subunits can be recognized in the Kettle Point, as well as the 'false Antrim' in the lower part of the Bedford shale (Figure 3-4). The TOC values for various samples taken from KP-24 are as follows:

Subunit 1:
TOC is highly variable, ranging from 4% to 14% and averaging 8.5%.

Subunits 2, 3 and 5:
All average approximately 7%.

Subunit 4:
TOC is negligible.

Subunit 6:
TOC increases rapidly towards the top of the unit and reaches 15% just below the top contact. The top 10 m averages over 10% TOC.

These results suggest that there are two potential zones of interest in the Kettle Point Formation, Subunit 6 at the top and Subunit 1 at the bottom.

Results of FA for core samples from KP-24 are shown in Figure 3-5. Subunits 1 and 6 both average about 40 L/t (9.5 US gal/ton). The OGS conducted hydrogen retorting tests on samples from these zones in another hole. They found that the response is similar to that of other eastern Devonian organic shales, with oil yields being more than doubled under hydrogen retorting (pyrolysis) conditions.

Barker et al. (1983) reported on the results of preliminary evaluation of the type and quality of the organic matter of the Kettle Point Formation, including:

(1) vitrinite reflectance;
(2) conodont colour alteration;
(3) thermal alteration index; and
(4) visual assessment.

This evaluation indicated that the organic matter in the Kettle Point Formation is marginally mature to immature, is predominantly kerogen, and is of marine origin. Subsequently however, results of kerogen aromaticity tests indicated that some of the organic matter is of terrestrial origin. Since terrestrial organic matter tends to be poorer in hydrogen than marine sapropelic organic material, its FA : TOC ratio is lower.

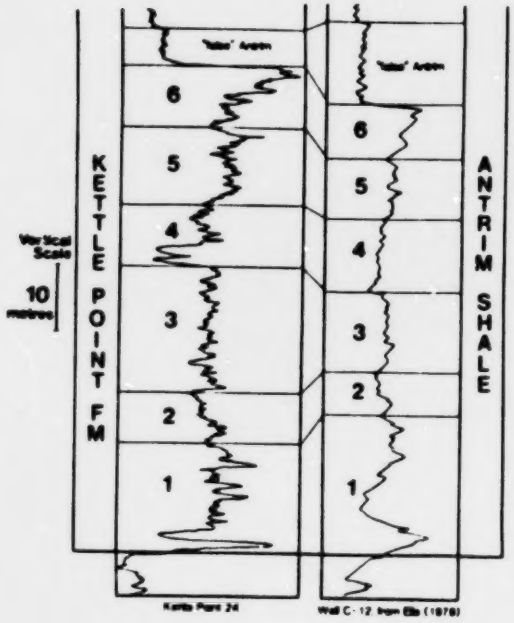

FIGURE 3-4: Gamma ray log correlation between Michigan (Sanilac County) and Ontario (OGS well KP-24) (source: Russell and Barker 1983).

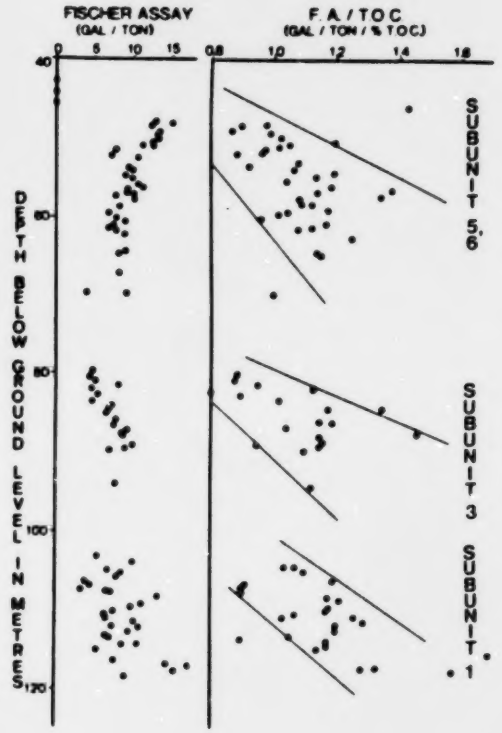

FIGURE 3-5: Plot of FA yield and ratio of FA yield to total organic carbon content (OGS well KP-24) (adapted from Russell and Barker 1983).

3.4 THE LONG RAPIDS FORMATION

3.4.1 GENERAL

The Long Rapids Formation is the youngest Paleozoic rock unit in the Moose River Basin and is the lithologic and stratigraphic equivalent of the Kettle Point Formation. It is unconformably overlain by Cretaceous or Quaternary sediments.

Savage and Van Tuyl (1919) observed exposures of black shales along the Abitibi River in the James Bay Lowland, and recognized that they are the equivalent of the Upper Devonian black shales of the Appalachian and Michigan Basins. Subsequently, these shales were named the Long Rapids Formation but, as Telford (1984) points out, they have remained poorly known because of their relatively poor exposure in a remote location with difficult access.

3.4.2 INVESTIGATIONS BY THE OGS

Because of the remoteness of the area underlain by the Long Rapids Formation and the logistical difficulties involved in working in the Moose River Basin, the OGS adopted a somewhat different approach than they had used in investigating the oil shales in southern Ontario. The initial studies, in September 1984, entailed a detailed structural, stratigraphic and sedimentological study of an outcrop along the Abitibi River at Long Rapids. A small diamond drill was also used at the site, and core samples were taken to assist in the stratigraphic and structural investigations.

Since 1975, the OGS has also carried out six drilling programs in the Moose River Basin, in an effort to establish the lignite resource potential of the Cretaceous sediments in the region. Many of the drill holes have been extended through the Cretaceous sediments into the Devonian units, including the Long Rapids Formation. In addition, drilling programs have been completed in the basin by several private petroleum and mineral exploration companies.

3.4.3 THICKNESS, EXTENT AND LITHOLOGY

Russell and Telford (1984, p. 118) also reviewed the thickness and lithology of the Long Rapids Formation, and noted that the thickest section (85 m) was reported by Dyer and Crozier (1933) from the Onakawana 'A' borehole. Sanford and Norris (1975) reported that a stratigraphic section exposed on the Abitibi River, the type locality, was measured at 37 m. However, recent investigations by the OGS have shown that:

(1) only the lower member and basal middle member are present in the type locality; and

(2) the distribution of the Long Rapids Formation in the southeastern part of the Moose River Basin is restricted to a much smaller area than had been shown previously (Figure 3-6).

Russell and Telford (1984) have summarized the lithologic sequence exposed along the Abitibi River at Long Rapids as follows:

1. The basal contact of the formation is disconformable: blue–grey plastic mud greater than 1 m thick overlies the brecciated limestones of the Williams Island Formation.
2. Fissile black shales, the type lithology of the Long Rapids Formation, overlie the basal unit.
3. Green–grey mudstone and shale, alternating with fissile organic-rich black shale overlie unit 2. This part of the section is about 5 m thick and is poorly exposed as a result of faulting.
4. The part of the section above unit 3. is fully exposed and consists of two parts:
   - — The lower part is 23 m thick. It consists of numerous cycles of green–grey calcareous mudstone or shale, followed by concretionary carbonate layers, which are sharply overlain by green or black shale.
   - — The upper section is about 8 m thick; it is mainly black fissile shale and is probably the zone of most economic significance.

3.4.4 DEPOSITIONAL ENVIRONMENT AND STRUCTURE

The presence of green–grey lithologies in the exposed section, their thickness and general characteristics, suggest that the environment of deposition was relatively shallow water. Since the black shales are interbedded with the grey–green facies, it is suggested that they were deposited in a similar environment.

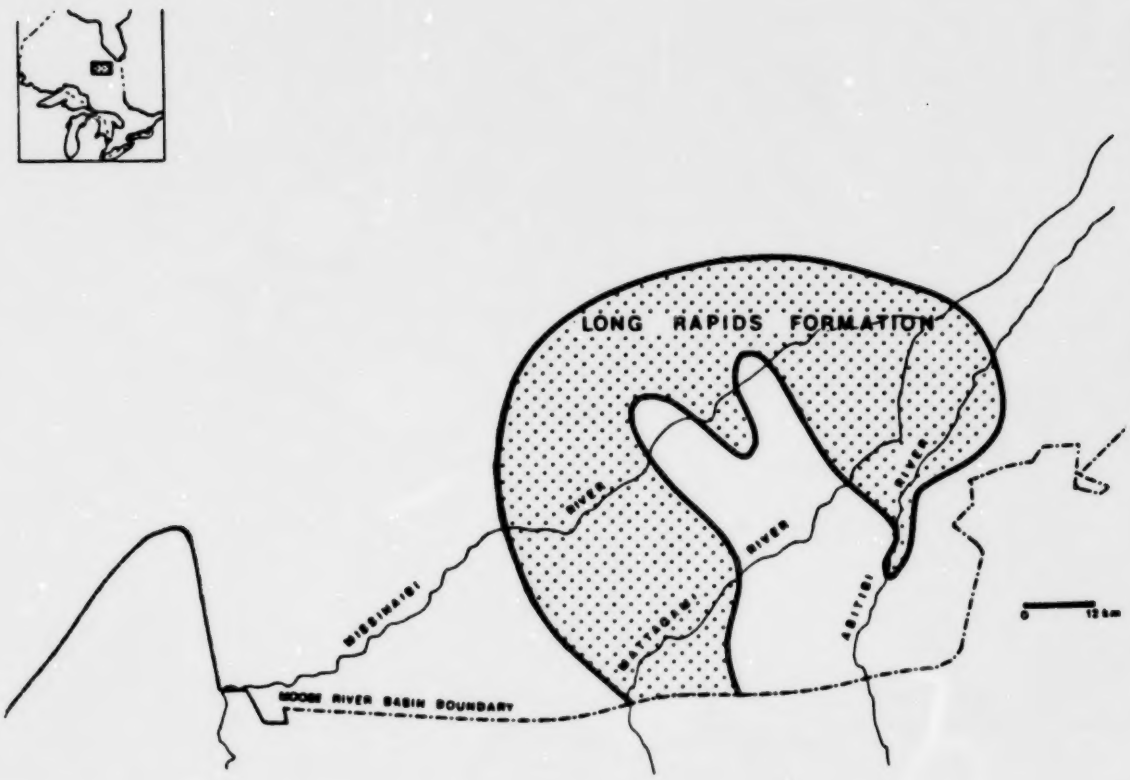

FIGURE 3-6: Distribution of the Long Rapids Formation (adapted from Telford 1984).

In addition to the faulting mentioned in the description of unit 3., many other faults and reversals are present in the exposed section along the Abitibi River. Russell and Telford (1984, p. 118) have concluded, from a brief inspection of other Devonian and Silurian units along the southern boundary of the Moose River Basin, that the structural geology of the area is much more complex than shown in presently available interpretations.

3.4.5 GEOCHEMISTRY

According to Telford (1984), the black shales of the Long Rapids Formation are organic-rich and several samples taken from the type section produced TOC values equivalent to an oil yield of about 50 L/t (12 US gal/ton). However, he concluded that much more stratigraphic and structural work is still required before an assessment of the hydrocarbon potential of the unit can be made.

The results of organic geochemical analyses were unfortunately not available for the present study. However, the Long Rapids Formation was the subject of a small metallurgical test program completed for the Ontario Ministry of Energy in 1983 by WGM. In that report, the results of FA from four drill holes are detailed as follows:

HOLE	LENGTH (m)	FA	
		L/t	US gal/ton
ONEX 82-01	12.2	35	8.3
ONEX 82-04	11.3	33	7.8
ONEX 82-05	7.3	33	7.9
LX-7A	11.0	33	8.0

Furthermore, the report states that hydrogen retorting of a composite sample from LX-7A increased oil yields to 86 L/t (20.5 US gal/ton).

3.5 THE MARCELLUS FORMATION

3.5.1 GENERAL

The Middle Devonian Marcellus Formation underlies a small portion of southwestern Ontario, on the northern shore of Lake Erie in the vicinity of Port Stanley, and extends eastwards beneath central Lake Erie into western New York State. The formation consists of grey and black bituminous shales and conformably overlies limestones of the Dundee Formation. It is completely buried by thick Pleistocene glacial and glaciolacustrine deposits, and can only be studied by obtaining data from boreholes.

Telford (1984) reports that Sanford (1968) correlated the Marcellus Formation with the Rogers City Formation, a limestone unit, in northeastern Michigan. Sanford concluded that the Marcellus Formation once covered all of southwestern Ontario, and suggested that most of the unit was removed by erosion before deposition of the overlying shales and limestones of the Hamilton Group. Rickard (1984), however, believes that the Marcellus is equivalent to shales of the Bell and Arkona Formations in the lower part of the Hamilton Group, and that lithological differences are due to lateral facies changes.

Telford (1984) has suggested that more precise lithological definitions of the various units and better biostratigraphic control are required in order to resolve this disagreement.

3.5.2 INVESTIGATIONS BY THE OGS

During late 1982 – early 1983, OGS drilled five shallow boreholes within what was believed to be the subcrop area of the Marcellus Formation in the Port Stanley area (Figure 3-7). In March 1983, a deep borehole was drilled near Port Stanley: it was cored from surface to the Precambrian basement, the total depth being 1,165.5 m.

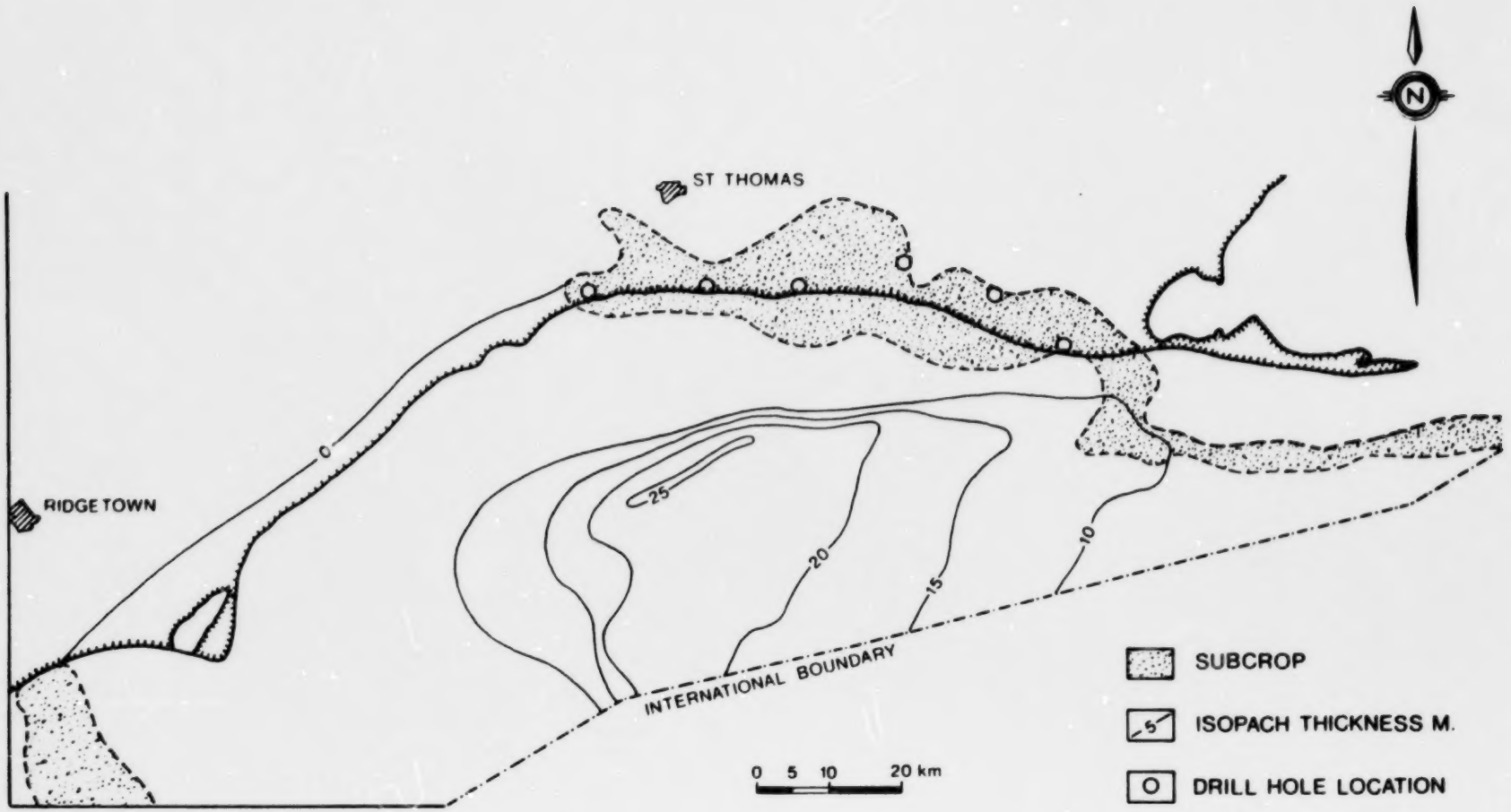

FIGURE 3-7: Isopach map of the Marcellus Formation (source: Telford 1984 and Musial 1982).

3.5.3 THICKNESS AND EXTENT

Of the five shallow holes drilled by OGS in the Port Stanley area in 1982–83, only three intersected beds of the Marcellus, as shown in Table 3-2.

The absence of the Marcellus in boreholes M-07 and M-09 suggest that revision of the existing subcrop map is required. The thickness of the Marcellus ranged from 2.95 m in M-06 to 11.52 m in M-05; overburden thicknesses ranged from about 50 to 100 m. Sanford (1968) reported that the Marcellus Formation beneath central Lake Erie reaches a maximum thickness of about 15 m (50 ft).

The deep drill hole completed near Port Stanley in March 1983 intersected 5.8 m of the Marcellus Formation and also encountered an oil-saturated zone of Cambrian sandstones.

3.5.4 DEPOSITIONAL ENVIRONMENT

The following discussion is from Musial (1982, p. 27–29):

> *The Marcellus shale forms the base of a great clastic wedge of the Middle and Upper Devonian in the Appalachian basin. As pointed out by James (1954), black shales such as the Marcellus seem to appear in the geosynclinal cycle just after the sediments formed on the aerated shelf and just before those derived from the rising geanticlinal ridge. The rise of the latter, prior to emergence within the geosyncline produces the semi-isolation required for black shale deposition.*
>
> *As Devonian time progressed, the eastern side of the Appalachian trough became almost filled with sediment, and the limit of bituminous shale deposition was pushed further and further west. ... At the time of its deposition, the Marcellus was probably the most distal facies of a turbidite fan originating from the southeast. The thickness increased due to the slow sedimentation of fine-grained siliceous and organic material in a very low energy, anaerobic environment.*

3.5.5 GEOCHEMISTRY

Thirteen core samples from the deep and shallow drill holes were analysed by rapid pyrolysis for their hydrocarbon content. The maximum value obtained for TOC

TABLE 3-2

MARCELLUS FORMATION: SUMMARY OF OGS RESULTS

Hole	Intercepts			Thickness of Overburden (m)	Total Organic Carbon (wt%)	Pyro-Probe Yield (wt%)[1]	Fischer Assay		
	From (m)	To (m)	Length (m)				Oil Yield		Gas + Loss (wt%)
							US gal/ton	wt%	
M-05	96.03	111.95	15.92	95.92	2.31	.60	—	—	—
	108.61	108.80	.19		11.40	2.90	15.40	5.90	2.40
M-06	88.22	96.95	8.73	87.96	1.94	.60	—	—	—
	93.64	93.86	.22		9.80	2.50	14.20	5.40	1.20
M-07	—	—	—	48.80	—	—	—	—	—
M-08	84.25	88.50	4.25	84.14	1.54	1.00	—	—	—
	87.89	88.09	.20		5.30	1.50	5.30	2.10	1.10
M-09	—	—	—	54.10	—	—	—	—	—
OGS 82-3 (deep)	—	—	5.77	79.85	—	—	—	—	—

[1]wt% carbon (methane equivalent).

content was 11.4%, with an average value of less than 2%. Using the conversion factors developed by Barker and Dickout et al. (1983), these figures translate to 51 L/t (12.2 US gal/ton) and 9 L/t (2.2 US gal/ton) of oil, respectively.

A low hydrocarbon resource potential is indicated for the unit by the generally low TOC values from these preliminary analyses, by the relatively thin and discontinuous nature of the Marcellus Formation in the Port Stanley area, and by the very thick overburden (Telford 1984, p. 5). However, WGM believes that the organic-rich beds are too thin to be exploited and we do not see any potential for the Marcellus.

3.6 THE COLLINGWOOD MEMBER OF THE LINDSAY FORMATION

3.6.1 GENERAL

In the Craigleith Provincial Park, on the shore of Nottawasaga Bay, there is a historical plaque that reads:

THE CRAIGLEITH SHALE OIL WORKS 1859

> *A growing demand for artificial light led to the establishment, in 1859, of a firm headed by William Darley Pollard of Collingwood. He erected a plant here to obtain oil through the treatment of local bituminous shales. The process, patented by Pollard, involved the destructive distillation of fragmented shale in cast-iron retorts heated by means of wood. The 30 to 35 tons of shale distilled daily yielded 250 gallons of crude oil, which was refined into illuminating and heavy lubricating oils. The enterprise, the only one of its kind in the province's history, failed by 1863. The inefficiency of its process made its products uncompetitive after the discoveries of "free" oil at Petrolia and Oil Springs, near Sarnia.*

The 'bituminous shales' are part of the Collingwood Member of the Lindsay Formation that outcrops along the shoreline by the park. The yield of crude oil described is equivalent to 37–44 L/t (9–10.5 US gal/ton).

The Collingwood Formation has been variously described as the Utica, the Gloucester, the Billings (even outside the Ottawa – St. Lawrence Lowland area), the Craigleith, the

Collingwood member of the Whitby Formation, and the lower Whitby of the Nottawasaga Group.

The organic-rich interbedded shales and limestones comprising the Ordovician Collingwood beds are contained within a subcrop belt, which extends from Manitoulin Island in the west through Collingwood and from there south-southeasterly across southern Ontario to the Toronto–Whitby area on the shores of Lake Ontario.

According to Macauley (1984), equivalent shales are:

(1) the Billings Formation in the Ottawa area;
(2) black shales of the Lachine Formation along the St. Lawrence River northeast of Montréal;
(3) the Mictaw shales of Gaspé; and
(4) the Utica shales of the Lake Champlain area.

Russell and Telford (1983, p. 1782–1783) reviewed the stratigraphic terminology of the Upper Ordovician shale units of southern Ontario, then discussed (ibid. p. 1787–1789) the significance of recent analyses of diamond drillcore samples through the Whitby and Lindsay Formations. They found that the organic-rich interbedded shale and limestone unit, known informally as the 'Collingwood Shales' and previously grouped with overlying non-calcareous shales, are actually in gradational contact with underlying sandstones of the Lindsay Formation. This gradational contact, together with a sharp decrease in carbonate and organic carbon contents at their top, lead to the renaming of these strata as the Collingwood Member of the Lindsay Formation.

3.6.2 INVESTIGATIONS BY THE OGS

The objective of the first phase of the OGS Oil Shale Assessment Project was to define the extent and oil shale potential of the Collingwood Member of the Lindsay Formation. In early 1982, a drilling program was carried out in three areas directly underlain by this unit at:

(1) Pickering, near Toronto;
(2) Craigleith, near Collingwood, on Georgian Bay; and
(3) Little Current, on Manitoulin Island.

A total of 26 holes were drilled to intersect the Collingwood Member. Eight of these were deeper holes drilled at Shelburne, Wiarton, Nobleton, Milton, Clarkson, Pickering, Little Current, and St. Joseph Island. The deeper holes were mostly drilled to provide OGS with good cored sections on a regional basis and to add to their knowledge of the geology and stratigraphy of southwestern Ontario. The 18 shallow holes were located as follows:

4 holes in the Toronto area;
11 holes at Caigleith; and
3 holes on Manitoulin Island.

3.6.3 THICKNESS, EXTENT AND LITHOLOGY

Russell and Telford (1983, p. 1787) reiterated their reasons for concluding that the interbedded Ordovician shales and limestones under study are more closely associated with the underlying Lindsay Formation, and for making member status within the Lindsay Formation preferable to proposing the shales as a separate formation. Therefore:

> *The Collingwood Member of the Lindsay Formation is . . . composed of interbedded organic-rich limestone and highly calcareous shale. The lower contact is placed at the highest occurrence of the characteristic nodular limestone of the Lindsay Formation. The top contact of the Collingwood Member, and thus of the Lindsay Formation, is placed where the black, fossiliferous highly calcareous shale (or marl) is first overlain by grey-blue or grey, non-calcareous shale.* (Russell and Telford, 1983, p. 1787).

Furthermore:

> *In present subsurface usage, the lower contact of the 'Collingwood Formation' is characterized as sharp, with brownish-black shales overlying brown, bituminous limestones (Beards 1967), but with the anomalous calcareous shale occurring in the top of the Lindsay (Beards' Cobourg) Formation in the Bruce Peninsula and on Manitoulin Island.*
>
> *The resistivity log shown by Beards (1967) for his typical Bruce Peninsula well shows that this calcareous shale unit is very organic; it is clearly equivalent to the organic-rich units sampled during (the OGS) study at Craigleith, near the type section of the Collingwood shales, now referred to the Collingwood Member of the Lindsay Formation.*
>
> *Our* (i.e., Russell's and Telford's) *observations show that the Collingwood Member also occurs in the Pickering area . . .*

Three additional boreholes drilled by the OGS in 1982 provided important data pertaining to the extent of the Collingwood Member in the subsurface. The organic-rich layer in a borehole drilled in the Don Valley brickyard, close to downtown Toronto, occurred between 118 and 120 m depth: this is not only very thin in comparison with the almost 7 m thickness near Pickering, but the organic content decreases dramatically over the 40 km distance between Pickering and the Don Valley location.

Significant thicknesses of the Collingwood Member were intersected in OGS boreholes at Nobleton and Corbetton. However, the overlying strata, both at these locations and in the hole drilled in the Don Valley brickyard, resemble the Thornbury Member; that is, the upper member of the Whitby Formation. This suggests that the Rouge River Member, or the middle member of the Whitby Formation, is present only in the area to the east of Toronto.

Figure 3-8 is a very preliminary map of the distribution of the Collingwood Member and of the lithology characteristic of the Rouge River Member. It shows clearly that both the organic-rich Collingwood Member of the Lindsay Formation and the Rouge River lithologies are relatively restricted facies.

To sum up, the Collingwood Member is more restricted, both stratigraphically and geographically, than had previously been believed. Also, whereas typical FA yields for the Collingwood Member are 49 L/t (11.7 US gal/ton) of oil, yields are negligible from the overlying shales, which have been identified as 'Collingwood Formation' in oil and gas well records.

3.6.4 GEOCHEMISTRY

Selected intervals of the core from the OGS drill holes in the Collingwood Member were chemically analysed by Dr. J. F. Barker and assistants at the University of Waterloo, to characterise the organic matter of the shales and the commercial hydrocarbon generation potential. The results of the analyses, with a brief description of the analytical technique, are presented in a report by Barker et al. (1983).

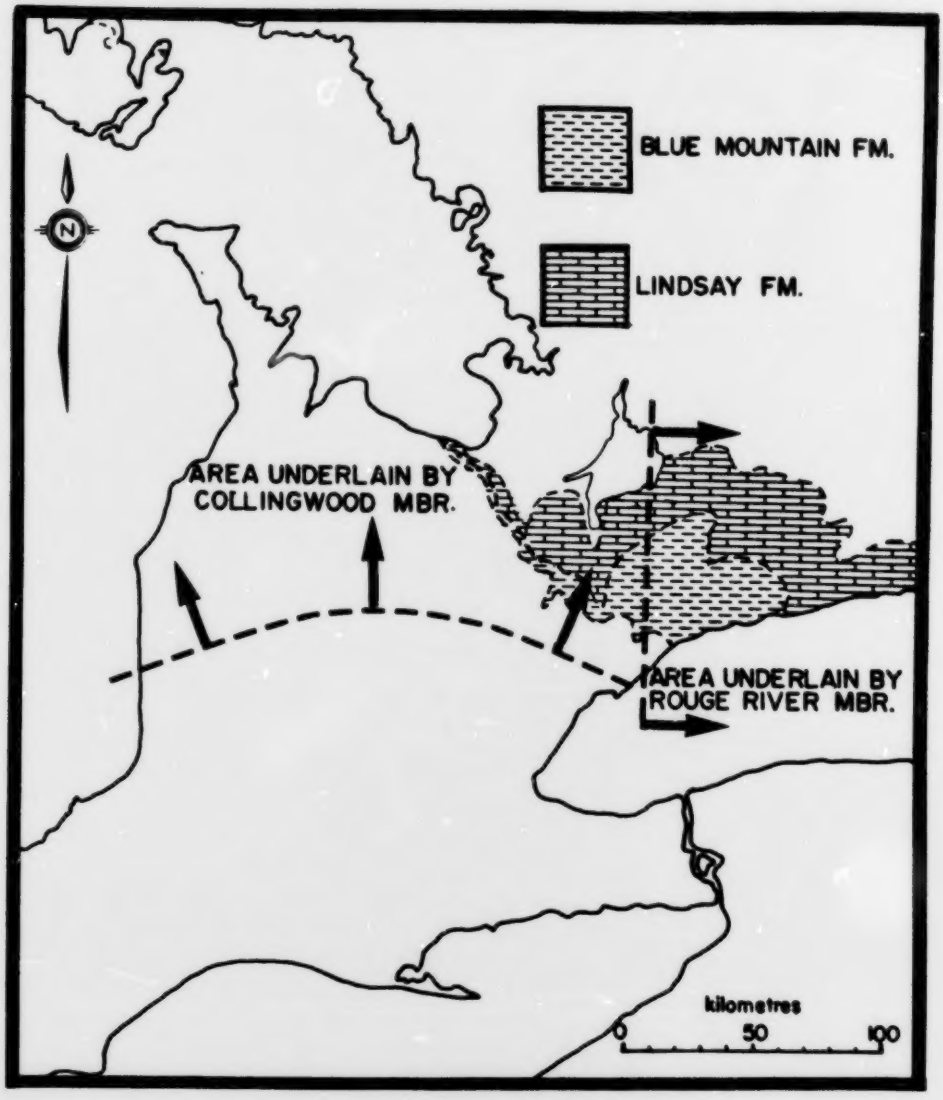

FIGURE 3-8: Sketch map showing tentative subsurface distributions of Collingwood Member of Lindsay Formation and Rouge River Member of Blue Mountain Formation (source: Russell and Telford 1984).

Samples were tested for TOC and TIC. Determinations were made of the H : C atomic ratio of kerogen and YP; FA were carried out, and total sulphur (TS) determinations were undertaken.

In hole SIS N°. 6, drilled some 2 km southeast of Sheguiandah on **Manitoulin Island,** there is an intersection of 5.26 m that contains 5.5% TOC. SIS N°. 5 roughly averaged over 4.58 m contains 5.25% TOC and SIS N°. 7 contains 6.63% TOC over 3.05 m. Only one FA was completed on the Manitoulin samples, yielding 23 L/t (5.5 US gal/ton) of oil with a specific gravity of 0.909, 34 L/t (8.2 US gal/ton) of water, and 1.2% gas and loss from a sample containing 7.19% TOC.

Pyrolysis yields (eight samples) ranged from 0.97% to 2.44%. H : C atomic ratio ranged from 1.22 to 1.36. Inorganic carbon content ranged from 3.22% to 7.45% and roughly appears to increase with depth.

OGS 83-5 at Little Current is reported to contain only 0.95 m of oil shale, whereas the thickness of the oil shale in OGS 83-6 on St. Joseph Island is reported to be 10.35 m (Harris 1985) and contains values similar to the other holes on Manitoulin. Depth to the top of the oil shale ranges from 15.35 m at Little Current (SIS N°. 5) to 158.45 m on St. Joseph Island. Some faulting is apparent near Little Current; OGS 83-5 encounters oil shale at depth of 67.75 m in between two holes that intersect the horizon at 15.35 m and 19.45 m, respectively.

An outcrop sample taken from somewhere on Manitoulin Island is described by Stromquist et al. (1984). This sample contains 6.16% TOC, yields 1.88% C (methane equivalent) from pyrolysis, 40 L/t (9.5 US gal/ton) of oil with specific gravity of 0.92 from FA with 7 L/t (1.66 US gal/ton) of water and 1.84% gas and loss. This sample is also reported to have an atomic H : C ratio of 1.23 and has been classified as Type II kerogen.

Some 13 holes were drilled in the **Craigleith area,** a number of which were located close to the old oil shale works. The most reliable intersections were in holes CLGD N°. 1, which contained 4.33% TOC over a thickness of 1.88 m (from 52.36 to 54.24 m) and CLGD N°. 4b, which contained 5.31% TOC over 1.82 m (from 46.65 m to 48.47 m).

Four FA were completed on the Collingwood in this area and yielded from 8 to 35 L/t (1.9 to 8.5 US gal/ton) of oil with specific gravities ranging from 0.895 to 0.941. Yields from pyrolysis (eight samples) ranged from 0.12% to 2.99% C (methane equivalent). Depths to the top of the oil shale ranged from 5.90 m to 107.05 m. This reflects the local topography rather than geological discontinuity. Stromquist et al. (1984) report on an outcrop sample containing 5.2% TOC, yielding 1.8% C (methane equivalent) upon pyrolysis, 39 L/t (9.28 US gal/ton) of oil with a specific gravity of 0.92 from FA with 10 L/t (2.3 US gal/ton) of water and 2.05% gas plus loss. The H : C atomic ratio of this material is 1.28 and the kerogen is classified as Type II.

In the **Toronto area**, the most reliable intersection is in SIS N°. 1, which contains 3.94% TOC over 2.82 m from 42.52 m to 45.34 m. This hole was drilled in Rouge Creek Park in Scarborough. Rough averages from SIS N°. 2 (Ajax) and SIS N°. 3 (Pickering) are slightly higher at 5.0% TOC over 2.84 m and 5.2% TOC over 3.05 m, respectively.

FA range from 7 to 13 L/t (1.6 to 3.2 US gal/ton) of oil with specific gravity of 0.91. Pyrolysis yields (14 samples) range from 0.17% to 1.99% C (methane equivalent). Depths to the top of the oil shale range from 22.8 m at Pickering to 118.45 m at the Don Valley brickyard.

Stromquist et al. (1984) report on an outcrop sample from Darlington that contains 2.17% TOC, yields 0.45% C (methane equivalent) from pyrolysis, 6 L/t (1.54 US gal/ton) oil with specific gravity of 0.91 from FA. The atomic H : C ratio is reported as 1.32.

3.7 SHALE OIL – RESOURCE POTENTIAL

3.7.1 DEFINITION OF RESOURCES AND RESERVES

A fundamental concept in the evaluation of mineral potential is the differentiation between **resources** and **reserves**. Definitions vary and ideas are in a state of evolution.

McKelvey (1972), of the USGS discussed the philosophy of resources and presented widely accepted concepts and a classification of mineral resources. The classification was modified by Brobst and Pratt (1973), who introduced certain modifications. Figure 3-9 summarizes their thinking.

Based on McKelvey (1972), and Brobst and Pratt (1973), resources are divided into three basic categories (Figure 3-9) in terms of degree of certainty of existence:

> **Identified resources** are specific bodies of mineral-bearing rock whose existence and location are known. They may or may not be evaluated as to in-situ volume, mass and overall grade. Identified resources include reserves.
>
> **Hypothetical resources** are undiscovered resources that we may still reasonably expect to find in known districts.
>
> **Speculative resources** are undiscovered resources that may exist elsewhere — either conventional types of deposits in broad geologic terrains or unconventional types of resources that have recently been recognized (or are yet to be recognized) as having some potential.

The authors further subdivided the resources in terms of economic viability. The vertical scale in Figure 3-9 shows that reserves are economically recoverable identified resources; subeconomic identified resources are called conditional resources.

Reserves are defined as known, identified deposits of mineral-bearing rock from which a mineral or minerals can be extracted profitably with existing technology and under present economic conditions.

Resources are defined as concentrations of naturally occurring materials in such form that economic extraction is currently or potentially feasible. Resources include: reserves as well as other mineral deposits that may eventually become available; known deposits that are not economically or technologically recoverable at present; and unknown deposits, rich or lean, that may be inferred to exist but have not yet been discovered.

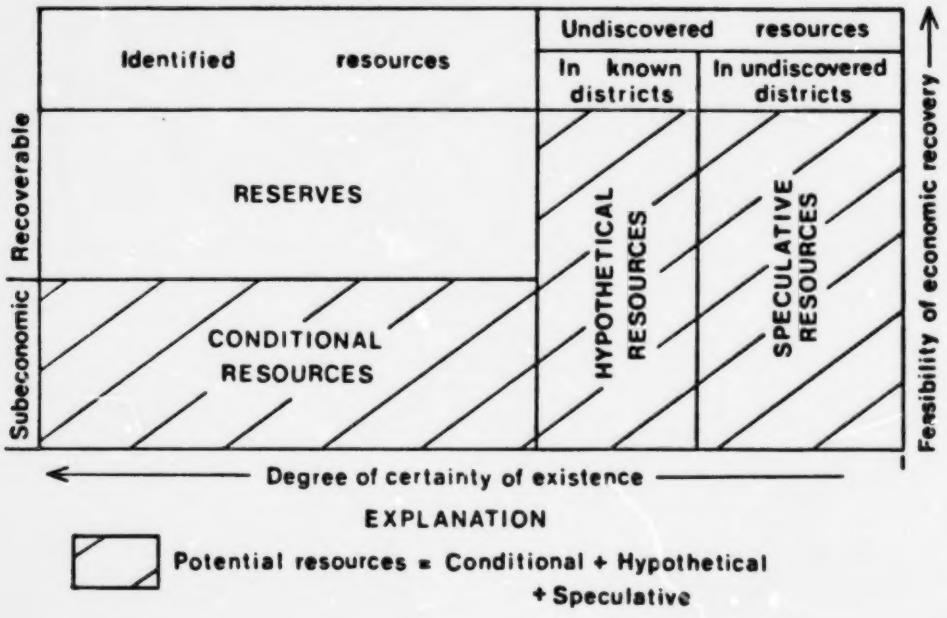

FIGURE 3-9: United States Geological Survey mineral resources classification (source: Brobst and Pratt 1973).

3.7.2 FACTORS CONSIDERED IN RESOURCE ESTIMATES

The Paleozoic sedimentary rocks in Ontario underlie some 400,000 km^2 of the Province. Published data indicate many fine-grained laminated units within these rocks that are at least partly organic-rich or kerogen-bearing and are reported to contain in excess of 5 wt% organic matter (4.4 wt% TOC) or are capable of yielding at least 2 wt% hydrocarbons by FA. These units are oil shale according to the definitions in Section 3.1.

For Brobst and Pratt (1973), an oil shale must yield a minimum of 63 L/t (15 US gal/ton) and be at least 4.5 m (15 ft) thick. These parameters were determined for the Green River oil shale of Colorado, which has a high conversion of kerogen to oil from FA; such a yield is equivalent to 5.7 wt% or about 63 L/t (15 US gal/ton). The kerogen in the Green River has a much higher hydrogen content than the Ontario shales and, at equal kerogen content, will yield twice as much oil.

However, because of improvements in materials handling technology since 1973 and the development of retorting in the presence of hydrogen that can double the oil yields of Ontario shales, we believe that a 20 L/t (about 5 US gal/ton) oil yield under FA may be considered as the lower limit for classifying an Ontario oil shale as a resource.

Furthermore, a resource should be mineable, or amenable to treatment by artificial methods to recover or convert the kerogen into a marketable commodity. Technology developments, in the last decade, and potential future developments, suggest that in the long run, it should be or will be feasible to treat a 2 m thick bed separately; therefore, Ontario oil shales of such thickness are considered resources. Failing this minimum thickness, the computed thickness times yields must be in excess of 8.8 m%/t or 40 m • L/t. Thus, a 1 m thick unit must contain 8.8 wt% TOC or yield 40 L/t (9.5 US gal/ton) by FA.

Of the many geological units in the Paleozoic of Ontario, only three meet our requirements for classification as shale oil resources: these are, the Kettle Point and Long Rapids Formations and the Collingwood Member of the Lindsay Formation. The

Marcellus Formation does not meet the combined thickness–yield requirement: TOC contents in excess of 4.4 wt% are known only for intersections less than 0.5 m thick.

The data is scattered over large areas. Sampling sites are, on average, more than 10 km apart and most of the resources are classified as hypothetical resources. Identified resources have been assigned around sampling sites to a radius of 2 km or for an area of 12.5 km^2: it is felt that lithological continuity in southern Ontario and in the Moose River Basin permits such extrapolation of data.

No reserves have been identified, the database is scant, and therefore no detailed evaluation of volume, mass and grade can be computed.

In our estimates, priority is given to the published and unpublished raw data generated by the sampling and testing program of the OGS. We have supplemented the OGS results with data generated by others, such as well-card data from the Petroleum Resources Section of the Ontario Ministry of Natural Resources.

We have decided to adopt a more conservative approach than the USGS by limiting extrapolation of data. For instance, the Collingwood Member is known from well data to underlie an area as large as 40,000 km^2 and the USGS definition would allow us to classify all of the organic-rich zone within this formation as identified resources. However, because there are no analytical results for the portion lying under Lake Huron, we have considered only the on-shore portion as a resource. Also, because of the wide spacing between sampling sites, we have decided to include the on-shore portion in the hypothetical rather than the identified resource category.

Furthermore, the resource estimates are based exclusively on shale oil yields under pyrolysis and do not include the amounts of off-gases evolved during pyrolysis. These gases can be used as a source of thermal energy and could increase the resources by some 5 to 10 wt% shale oil equivalent.

Lastly, the shale oil estimates are based on two retorting approaches:

(1) inert atmosphere retorting in surface plants with yields equivalent to FA, which converts 25% to 40% of the organic carbon to liquid hydrocarbons or shale oil; and

(2) retorting in the presence of hydrogen in surface plants with yields at twice FA yields. Hydrogen retorting converts 60% to 80% of the organic carbon to shale oil.

In the first approach, the resources are computed using the following formula:

$$Rfa = Area \times Thickness \times Density \times Yield$$

where: **Rfa** is the resource estimate based on FA oil yields and reported as cubic metres of shale oil; **Area** is the inferred area of influence in square metres of a given oil shale; **Thickness** is the average inferred thickness in metres over the area considered as a resource; **Density** is the density of the shale rock; and **Yield** is the yield by FA expressed in m^3 per tonne of shale.

In the second approach, the resources are computed using the formula:

$$Rhr = 2 \times Rfa$$

where **Rhr** is the resource based on oil yields from hydrogen recovery. For this approach, we used a factor of 2, although optimization will undoubtedly increase yields to more than double those of FA for some of the oil shale units.

3.7.3 KETTLE POINT SHALE OIL RESOURCE

From the OGS program (Table 3-3), 19 cores and numerous well cards at the Petroleum Resources Section indicate that the Kettle Point Formation underlies an area of some 2,000 km^2 of southwestern Ontario. The average thickness, using data from Brigham (1971) and Table 3-3, exceeds 30 m.

From the OGS sampling and analytical program, 18 holes showed that the organic-rich portion of the formation is up to 71 m thick, averages 32 m, and is capable of yielding from 18 to 38 L/t (4.4 to 9.2 US gal/ton) of shale oil by FA, averaging about 26 L/t (6.2 US gal/ton).

TABLE 3 - 3

DRILL HOLE DATA FOR RESOURCE ESTIMATES

GEOLOGICAL FORMATION OR MEMBER	HOLE N°.	INTERCEPTS			TOTAL ORGANIC CARBON (wt%)	PYRO-PROBE YIELD (wt%)[1]	FISCHER ASSAY		
		FROM (m)	TO (m)	LENGTH (m)			OIL YIELD		GAS + LOSS (wt%)
							US gal/ton	wt%	
Kettle Point	KP-10	32.19	44.45	12.26	7.67	2.10	9.20	3.90	1.30
	KP-11	26.60	53.53	26.93	5.28	1.00	4.40	1.70	1.00
	KP-12	23.51	34.85	11.34	6.17	1.20	6.90	2.70	1.40
	KP-13	27.92	41.03	13.11	6.55	1.40	5.20	2.00	1.00
	KP-14	22.57	54.70	32.13	4.82	1.20	5.70	2.20	.90
	KP-15	11.15	59.69	48.54	6.20	1.70	7.70	3.00	1.40
	KP-16	21.34	88.34	67.00	5.26	1.30	6.00	2.30	1.10
	KP-17	37.45	94.92	57.47	4.90	1.00	5.20	1.90	1.10
	KP-18	42.70	108.39	65.69	6.23	1.50	6.10	2.40	1.00
	KP-19	45.72	83.65	37.93	6.48	1.30	6.40	2.50	.80
	KP-20	13.00	22.49	9.49	7.10	1.20	5.80	2.20	.40
	KP-21	—	—	—	—	—	—	—	—
	KP-22	11.61	26.02	14.41	6.66	.54	7.00	2.70	1.30
	KP-23	20.12	40.25	20.13	5.92	1.40	6.30	2.50	1.40
	KP-24	47.82	118.83	71.01	7.13	1.90	8.40	3.30	1.30
	KP-25	33.56	93.14	59.58	6.52	1.80	6.60	2.60	1.40
	KP-26	32.05	55.18	23.13	6.92	1.70	7.20	2.80	1.00
	KP-27	10.67	32.92	22.25	6.97	1.60	7.40	2.90	1.00
	KP-28	14.26	28.96	14.70	6.68	1.50	5.40	2.13	.80
		Average		31.95	5.97	1.33	6.15	2.41	1.03
Marcellus	M-05	108.61	108.80	.19	11.40	2.90	15.40	5.60	2.40
	M-06	93.64	93.86	.22	9.80	2.50	14.20	5.35	1.20
	M-08	87.89	88.09	.20	5.30	1.50	5.30	2.10	1.10
		Average		.20	8.83	2.30	11.63	4.35	1.57
Long Rapids	ONEX 82-01	—	—	12.20	—	—	8.31	3.20	—
	ONEX 82-04	—	—	11.30	—	—	7.78	3.00	—
	ONEX 82-05	—	—	7.30	—	—	7.85	3.00	—
	LX-7A	—	—	11.00	—	—	8.00	3.00	—
		Average		9.87	8.50		7.88	3.00	
Collingwood	SIS-3	30.02	34.14	4.12	6.32	1.83	—	—	—
	SIS-5	16.00	20.58	4.58	5.24	1.80	—	—	—
	SIS-6	41.57	44.44	2.87	6.67	1.90	—	—	—
	SIS-7	19.05	22.86	3.81	5.91	2.42	—	—	—
	CLGD-4b	46.65	58.67	2.02	5.08	2.41	—	—	—
		Average		3.48	5.84	2.07			

[1]wt% carbon (methane equivalent).

A total shale oil resource of 4,160 million m^3 (26 billion bbl) is inferred by FA using an area of 2,000 km^2 of subcrop, a thickness of 32 m, an average yield of 26 L/t (6.2 US gal/ton) by FA, and a density of 2.5 for the in-situ rock. Of the total, we have classified 91% as hypothetical resources and the remaining 9% as conditional identified resources. The latter includes some 320 million m^3 (2 billion bbl) of oil in shale yielding more than 25 L/t (6 US gal/ton) and 50 million m^3 (300 million bbl) in rock yielding 50 L/t (12 US gal/ton). It should be stressed that resources classified as conditional identified are low relative to the hypothetical resources only because of the limited amount of sampling to date. Further work will undoubtedly increase our level of confidence in these resources.

Hydrogen retorting should increase the total resource of the Kettle Point to 8,320 million m^3 (52 billion bbl). The conditional identified resource then becomes 640 million m^3 (4 billion bbl) in rocks yielding 52 L/t (12.5 US gal/ton) and 100 million m^3 (630 million bbl) in rock yielding in excess of 100 L/t (24 US gal/ton).

3.7.4 LONG RAPIDS SHALE OIL RESOURCE

The Long Rapids Formation is believed to underlie some 5,000 km^2 in the Moose River Basin. Analytical results from the formation are very scarce; however, results of the recent OGS program should become available in the near future.

Near Williams Islands, organic shale outcrops, with a cumulative thickness of 21 m, were reported by Sanford and Norris (1975). The shale is believed to be in the lower part of the Long Rapids Formation. According to Telford (1984), several samples taken from the type section are organic-rich: TOC content indicated that oil yields by FA should be at about 50 L/t (12 US gal/ton).

Four holes drilled in the south part of the basin intersected from 7 to 12 m of shale yielding 33 L/t (8 US gal/ton) under FA (Watts et al. 1983).

A total shale oil resource of 4,125 million m^3 (26 billion bbl) is inferred by FA assuming a single shale horizon 10 m thick within the 85 m thickness of the formation,

5,000 km^2 of subcrop, an average yield of 33 L/t (8 US gal/ton) shale oil, and a rock density of 2.5. Hypothetical resource is estimated at 4,092 million m^3 (25.8 billion bbl). A conditional resource of 33 million m^3 (200 million bbl) is indicated.

Hydrogen retorting should increase the total resource to 8,250 million m^3 (52 billion bbl). A conditional resource of 66 million m^3 (400 million bbl) is indicated for shale that should yield in excess of 60 L/t (14.4 US gal/ton).

3.7.5 MARCELLUS SHALE OIL RESOURCE

The Marcellus Formation does not outcrop and is directly overlain by thick unconsolidated overburden. Of six holes drilled by the OGS to sample the formation, two holes intersected the older Dundee Formation directly below the younger Pleistocene sediments. The other four holes intersected from 3.18 to 11.52 m averaging less than 2.31 wt% TOC in dark grey to brown to black calcareous shale with sublithographic limestone.

The large variation in thickness and the absence of the Marcellus Formation in two holes indicate that a large portion of the unit has been removed by erosion. The organic-rich units are less than 30 cm thick and too thin to be amenable to extraction. Subcrop is patchy and the inferred on-shore extent is believed to be less than 300 km^2.

No portion of the Marcellus Formation meets the combined thickness–yield requirement: TOC contents in excess of 4.4 wt% are known only for intercepts less than 0.5 m thick. Therefore, we have not indicated any resources for the Marcellus Formation.

3.7.6 COLLINGWOOD SHALE OIL RESOURCE

The Collingwood Member of the Lindsay Formation is known to underlie an area in excess of 40,000 km^2 north of a line joining Toronto, on Lake Ontario, to Goderich on Lake Huron. A belt of subcrop extends from Manitoulin Island on Georgian Bay through Collingwood to the Toronto–Whitby area, a distance of some 500 km.

The thickness and organic content of the Collingwood is locally variable. On Manitoulin the thickness averages 4 m and TOC content is above 5.5 wt%. At Collingwood the thickness is only 2 m with the TOC content in the 4–5 wt% range. Near downtown Toronto, it is 2 m thick with TOC content being less than 2 wt%.

The oil shales of the Collingwood Member are thin and relatively low in organic matter content. We inferred that less than 2% of the subcrop area has a resource potential. We have estimated total shale oil resources of only 195 million m^3 (1.2 billion bbl) based upon an area of 1,000 km^2, a thickness of 3 m, a yield by FA of 26 L/t (6.2 US gal/ton), and a rock density of 2.5. We believe that a conditionai identified resource of 20 million m^3 (126 million bbl) of shale oil exists in the Collingwood–Manitoulin outcrop belt. For this estimate, we have used an extrapolated oil yield based on Barker's (Barker et al. 1983) formula:

$$FA\ (L/t) = 4.6\ TOC - 0.73.$$

Again, hydrogen retorting should double the total resource to 390 million m^3 (2.5 billion bbl). A conditional identified resource of 40 million m^3 (250 million bbl) in rocks that should yield in excess of 52 L/t (12.5 US gal/ton) over a thickness of 3 m.

3.7.7 SUMMARY OF SHALE OIL RESOURCES

The Kettle Point, Long Rapids and Collingwood oil shale units represent a cumulative shale oil resource potential of **8,480 million m^3 (53 billion bbl)** by FA (Table 3-4). Retorting in the presence of hydrogen should bring that total to **16,960 million m^3 (106 billion bbl)** (Table 3-5).

The total identified resources for the three formations amount to about 5% of the total or 846 million m^3 (5.3 billion bbl) by hydrogen retorting; 423 million m^3 (2.7 billion bbl) by FA. As mentioned above, there is every expectation that further drilling and sampling will undoubtedly result in an increase in the conditional identified resources.

TABLE 3-4

SHALE OIL RESOURCES OF ONTARIO

BASED ON FISCHER ASSAY BY OGS

(resources in millions of m^3; oil yields in L/t of rock)

Geological Formation or Member	IDENTIFIED RESOURCES (L/t)				HYPOTHETICAL RESOURCES (L/t)				Total
	20–40	40–60	60–80	+80	20–40	40–60	60–80	+80	
Kettle Point	320	50	—	—	3,200	540	50	—	4,160
Long Rapids	33	—	—	—	3,450	590	52	—	4,125
Marcellus	—	—	—	—	—	—	—	—	—
Collingwood	20	—	—	—	175	—	—	—	195
	373	50	—	—	6,825	1,130	102	—	8,480

TABLE 3-5

SHALE OIL RESOURCES OF ONTARIO

BASED ON HYDROGEN RETORTING

(resources in millions of m^3; oil yields in L/t of rock)

Geological Formation or Member	IDENTIFIED RESOURCES (L/t)				HYPOTHETICAL RESOURCES (L/t)				Total
	20–40	40–60	60–80	+80	20–40	40–60	60–80	+80	
Kettle Point	—	640	—	100	—	6,400	1,080	100	8,320
Long Rapids	—	—	66	—	—	—	6,900	1,284	8,250
Marcellus	—	—	—	—	—	—	—	—	—
Collingwood	—	40	—	—	—	350	—	—	390
	—	680	66	100	—	6,750	7,980	1,384	16,960

4. MINING ONTARIO OIL SHALES

4.1 GENERAL

The aim of this preliminary review of mining is to determine the best methods of exploiting some of the oil shales in Ontario, employing mining methods and equipment currently in use on comparable mineral deposits. This may exclude some methods such as mechanical cutting of the oil shale. However, this approach is justified in view of the limited information available and the absence of prior experience in mining them.

Certain assumptions are presented regarding the quality, attitude and location of the shales in order to keep the scope of this mining study within manageable limits. A wide range of choices exists; obviously, therefore, the method with best economic potential, that is the simplest and lowest cost method, must be selected.

The oil shale deposits considered here are within the Kettle Point and Long Rapids Formations of Upper Devonian age, and the Collingwood Member of Upper Ordovician age. All of these units contain some organic matter; therefore, if they are amenable to one or more proven methods of mining, there is some possibility that they may be exploited.

Two key factors must be considered when planning to mine oil shales in Ontario:

(1) the unit value of the shale is low under existing economic conditions; and

(2) the formations are relatively thin nearly horizontal, and are spread over large areas.

Since the unit values are low, the mining method selected must have a low unit cost. Therefore, a large, efficient, and reliable operation with a large and continuous output is required.

Any operation that has large lateral dimensions also has a constantly increasing haulage distance and a widening impact on the surface; consequently, the maximum

emphasis must be placed on efficient materials handling, in order to control costs and restore the surface to a useable condition.

In view of these restrictions, only two methods of mining oil shales in Ontario are possible. Shallow deposits may be mined by the open-cast method of surface mining; deep deposits may be mined by the room-and-pillar method of underground mining. Each of these methods offer numerous options with regard to breaking, loading and hauling. Shales that are too deep to be economical for surface mining, but have insufficient cover to give roof support for underground mining, must be considered unminable at this time.

4.2 SURFACE MINING

Open-cast mining is defined here as the operation of removing the overlying waste, either soil or rock, to expose the valuable mineral; the removal of the valuable mineral; and the replacement of waste in the depleted zone in one continuous operation. In this type of mining, land reclamation is an important element, as some of the costs may be recovered through subsequent disposal of the land for other uses.

Perhaps the most critical phase of open-cast mining is waste removal, particularly as depth of mining increases and the thickness of the mineral zone decreases. Consequently, emphasis is placed on the use of large and efficient loading and hauling units; that is shovels, draglines, bucket wheels, trucks, and conveyors. The optimum plan is one that reduces or eliminates double handling and keeps haulage distances to a minimum.

In mining waste, a large V-cut is removed above the deposit, exposing an area on top wide enough to permit mining of the valuable mineral in relative safety. The slopes of the cut are kept below the natural angle of repose of the waste in order to eliminate slumping. Figure 4-1 illustrates the method using a large walking dragline. In this method, patented many years ago, the dragline strips an intermediate working level ahead of itself. It then operates from this level and excavates down to the top of the mineral deposit.

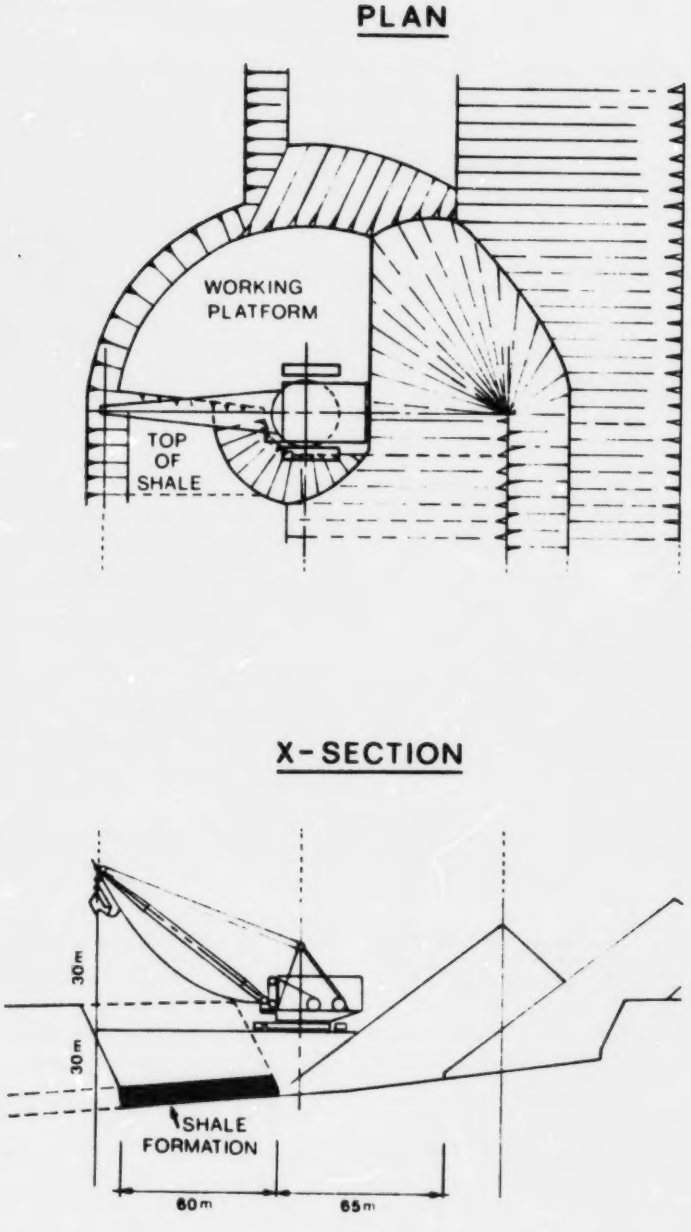

FIGURE 4-1: Plan and cross-section for open-cast mining, using the dragline bench method (adapted from Weimer 1969).

Large open-cast operations may be used, when waste to ore ratios are as high as 10 : 1 and depths to the valuable material are 100 m or more. The limits are set not only by the mechanical capabilities of available machinery, but more importantly by the net value of the material and the scale of operation. The limits that can be reached will only be determined by experience and, as experience is gained, the limits will be extended.

Mining of the mineral formation is a smaller operation than handling the waste because of the high waste to ore ratios; therefore, the two are usually separate operations. Smaller equipment is used and haulage distances increase as the mining moves farther away from the central processing plant. Breaking of the shale will probably be by blasting during the early developments, but the investigation of alternate methods of breaking or cutting could result in a significant reduction in costs.

Extraction of the oil shale formation and the stripping–backfilling operation require careful coordination so that both may proceed at the same time. The need for implementation of a grade-control program and provision of alternate working faces are problems that may have to be dealt with.

4.3 UNDERGROUND MINING

Room-and-pillar mining has many variations, but the controlling factors are:

(1) the thickness and strength of the economic mineral deposit; and
(2) the strength of the formation overlying it.

The deposits must also have uniform unit value and constant thickness to be suited to large rooms. Obviously, large rooms and small pillars are essential to high rates of recovery. Figure 4-2 shows a typical room-and-pillar operation. This is often achieved by various forms of roof support or by controlling the subsidence of the roof so as not to impede extraction of the valuable mineral. However, controlled

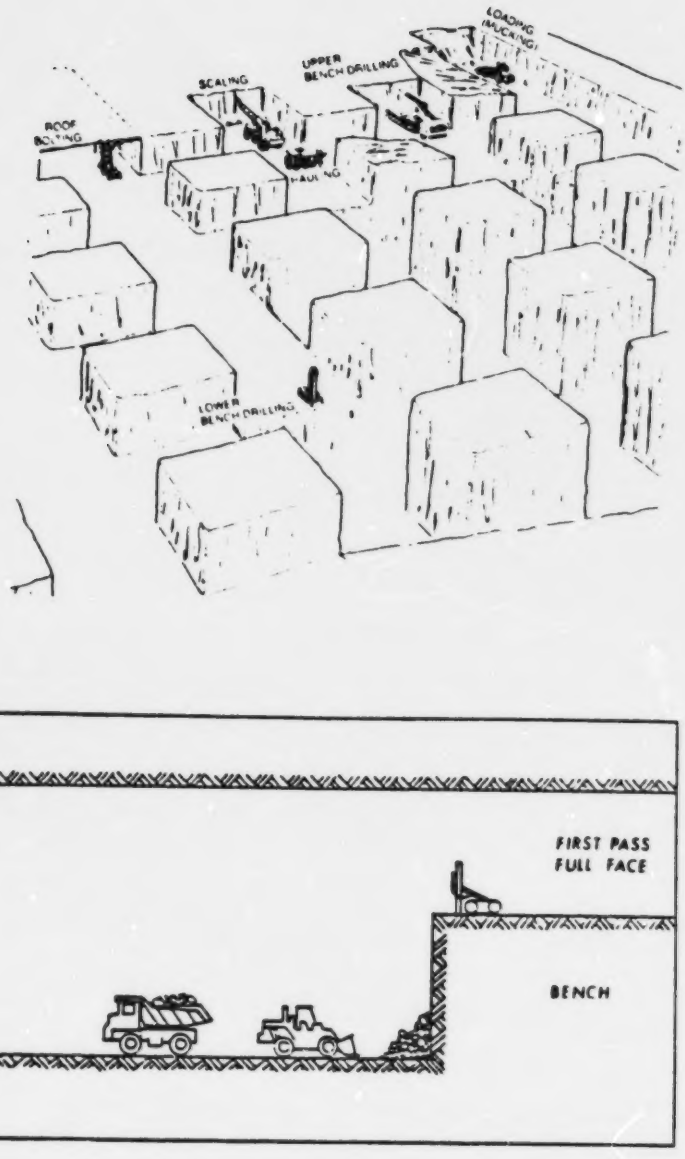

FIGURE 4-2: Room-and-pillar mining concept with section (sources: US Congress 1980 and TRW 1979).

subsidence may, especially in shallow deposits, come to the surface creating additional problems for the operation.

The coal industry, in particular, has developed specialized equipment to mine narrow seams (less than 2 m) using hydraulic supports, coal cutting machines and conveyor systems, in a variation of room-and-pillar mining called longwall mining. At the present state of development of the oil shale industry, longwall mining is not considered applicable, as there is little information on how the overlying formations might subside, and the suitability of the shale to cutting is unknown. Also, it is quite likely that machines designed for cutting coal would have neither the power nor the ruggedness for cutting shale. At this very preliminary stage of examination of oil shales in Ontario, deposits probably exist that are more suited to proven mining methods. The applicability of the proven methods should be examined in detail before the untried methods are considered.

As the thickness of a deposit increases, room size can be reduced and the same level of recovery maintained. Roof support can therefore be improved. Furthermore, the thicker formation allows for the use of more conventional breaking, loading and haulage systems. The transition continues as the thickness of the formation increases and double benching becomes possible.

The most critical factor in underground mining will be the breaking of the shale. In the early periods of development of the industry in Ontario, drilling and blasting will be the only practical approach. Little is known about the breakage characteristics: this may present problems, both in roof support, where the overlying formations may be weak, and in loading and hauling, which must be fast and efficient.

Roof support will have to be approached in three ways. First, the strength of the roof will be affected by the dimensions and the orientation of the rooms and pillars, and the layout of haulage and ventilation systems. Second, some form of intermediate support, such as roof bolts, will probably be required, both in areas of weakness and in areas of prolonged use. Third, backfilling will be an integral part of the operation since, by volume, there will be more spent shale than original shale. By returning

spent shale to the worked-out sections, the potential for surface subsidence is reduced and an opportunity is provided for future recovery of pillars.

Broken material, containing no oversize and having an average size of somewhat less than 20 cm, is the easiest to load and haul, therefore heavy equipment can be utilized to its maximum capacity in handling this material. This ideal condition is usually not attainable with material broken by blasting. Consequently, some form of secondary breaking is commonly necessary, usually by a breaker or crusher located at an intermediate transfer point in the underground workings. For example, a load–haul–dump unit may deliver run-of-mine material to a transfer point, where the material is loaded onto a conveyor through a grizzly. Any oversize is broken at that point.

The most desirable method of reducing the size of run-of-mine material is underground crushing, but with flat deposits the method has certain drawbacks. As the mining face advances, the haulage distance of run-of-mine material increases. At some point, therefore, the crusher may have to be relocated. This is a high-cost item, since the crusher is a large and permanent installation. In any event, underground crushing is mandatory if material is to be hoisted to surface in a shaft, because free-running material is required for automated loading and dumping systems when operating large-volume, low-grade mines.

Shaft hoisting is the most efficient method of bringing material to surface as, by design, the only work done in the system essentially is that required to raise the material. However, shafts require a large capital outlay and, for flat-lying deposits, the underground haulage distance to the shaft continues to increase as the mining face advances. The result is an operation with several shafts or an operation with very long underground haulage systems.

Conveying to surface is a possible alternative that is competitive with shafts for shallow deposits. The cost of driving a decline is usually cheaper than the cost of sinking a shaft. The conveyor can also be used as a collector and be fed from several locations in the mine. The conveyor system can, however, be more costly if it must pass through weak ground, since the tunnel must be heavily reinforced, particularly if there are large thicknesses of glacial till overlying the formations.

Although underground mining is more complex than open-cast mining, it offers the advantage of minimum disruption of the surface when conditions are right. Therefore, because of the widespread distribution of the oil shales in Ontario, it may be preferable to select a place or places where the shale can be mined underground. The essential criteria would be for the selected deposit to be deep enough and thick enough to permit a high level of recovery of the shale.

4.4 MINING METHODS FOR ONTARIO OIL SHALES

4.4.1 GENERAL

From the foregoing general discussion, preliminary plans for mining each of the formations containing hydrocarbons can be examined. To do this, however, presupposes certain things, including the general assumption that either open-cast or room-and-pillar methods are applicable, using currently available equipment with proven operating history under comparable conditions. It is also assumed that, in the event of a decision to develop the deposits, there will be an ongoing research and development program into methods and equipment. On this basis, the plans being put forward here must be considered as first generation, and many untried mining methods and items of equipment must be set aside at this time.

For all of the formations, both surface mining and underground mining methods have been examined. For each method, mining rates of 2,000 t/d and 20,000 t/d have been selected. The smaller rate is of interest as a substantial pilot operation, both to feed pilot-process plants already developed on this scale and for devising the best scheme of mining. It is a reasonable assumption that a daily mining rate of 20,000 tonnes of shale will yield 1,600 m^3 (10,000 bbl) of oil per day if processed by hydrogen retorting. This then would be a small commercial operation that would be well within the capacity of available mining machinery for both surface and underground. Also, it is a suitable module for doubling or tripling in size in the future.

The selected methods of surface mining for both rates of extraction are based on the assumption that the waste material can be removed without any drilling and blasting.

For the 2,000 tonnes rate, rippers and scrapers are the selected method, and for the 20,000 tonnes rate, either shovels, draglines or bucket wheels are considered applicable. All of these types of equipment have a proven record of operation in the types of material expected to be encountered over the oil shale deposits in Ontario.

It is assumed that the actual extraction of the oil shale in the surface method will require drilling and blasting; therefore, shovels and trucks are the selected method of loading and hauling the shale. However, at the lower rate of mining front-end loaders are an alternative to shovels.

For the underground methods of mining, because of the assumed need to drill and blast, the best means of handling the shale currently available are by load–haul–dump units, combined with a conveying system to bring the material to surface.

More detailed descriptions of the two mining methods are given in Appendix I.

4.4.2 KETTLE POINT FORMATION

The Kettle Point Formation underlies a large portion of southwestern Ontario and is the most likely formation to be exploited to yield commercial quantities of oil. Because of its wide distribution, it may be possible to select areas where it can be mined by either surface or underground methods, under reasonably favourable conditions.

Although there are hardly any exposures of this formation at surface, it is generally near surface and certainly within the range that might be considered for open-cast mining. As is normally the case, open-cast mining would require at least temporary disruption of a large surface area. For example, mining of a 10-m thickness of shale, having a 30 m thickness of overburden (a waste to ore ratio of approximately 3 : 1), would require removal of 21 million tonnes of waste material and disruption of some 0.30 km^2 of land annually.

Since the Kettle Point Formation is distributed widely throughout southwestern Ontario, it may be possible to select sites that are suited to either surface or underground mining. For open-cast mining, overburden and waste should be preferably removed without blasting. To be suitable for underground mining, the oil shale horizon must be covered by an overlying formation strong enough to allow the opening of large rooms with minimum subsidence.

What little information is available on the engineering characteristics of the formations above the Kettle Point indicates that it is of medium strength and can be self-supporting. However, in most cases, the overlying formation is absent and the Kettle Point directly underlies unconsolidated overburden.

4.4.3 LONG RAPIDS FORMATION

In the James Bay Lowlands, this formation is not as well defined as the Upper Devonian in southwestern Ontario. However, the available information indicates the possible existence of economic thicknesses of shale at depths that may be amenable to either surface or underground mining methods.

The climatic conditions in the James Bay Lowlands would not be a deterrent to an open-cast operation, but the generally low, swampy nature of the area may restrict the number of sites suitable for surface mining.

In some areas the formation is below the more recent deposits of lignite, so that at some future date consideration might be given to mining both lignite and oil shale from the same entry points. At this time, however, there is insufficient data on which to base any reasonable assumptions in this regard.

4.4.4 COLLINGWOOD FORMATION

The oil shales of the Collingwood Formation are quite variable in thickness and in organic carbon content. A 2 m section of oil shales was exploited, in the Craigleith area near Collingwood, prior to the discovery of oil at Oil Springs. The price of oil at

that time was $10/barrel. This would be equivalent to some $160/barrel in 1985 dollars.

Recent studies indicate, however, that greater thicknesses with equivalent oil yields by FA exist in the vicinity of Little Current on the north side of Manitoulin Island.

The Collingwood Formation, the oldest of the oil shales in Ontario, is generally overlain by more competent strata than the Kettle Point and Long Rapids Formations. This formation may be more amenable to underground mining than the others. However, since the best intersections are near surface, we expect that the Collingwood Formation would be mined by open-cast rather than underground methods.

4.5 SUMMARY OF COSTS

4.5.1 OPERATING COSTS

Preliminary estimates of the costs of mining the oil shales in Ontario have been developed. These are order-of-magnitude estimates for representative surface and underground operations derived from average costs of mining metallic and non-metallic minerals in Canada and the USA.

More details of the basis of estimate are given in Appendix I to this report. Generally, conditions were selected that seemed applicable to the shales in Ontario.

The operating costs are summarized below in Canadian dollars for mid-1982:

	Cost Per Tonne	
	2,000 t/d	20,000 t/d
SURFACE MINING		
Clearing	$ 0.04	$0.01
Removing Overburden	1.80	0.85
Drilling and Blasting	1.65	0.21
Excavating, Loading and Hauling	1.80	0.70
Restoration During Production	0.22	0.10
General Operating Costs	0.25	0.14
Drainage and Disposal	0.08	0.02
Administrative Expenses	0.21	0.18
TOTAL	$ 6.05	$2.21

	Cost Per Tonne	
	2,000 t/d	20,000 t/d
UNDERGROUND MINING		
Development During Production	$ 1.89	$0.80
Stope Preparation	5.68	1.12
Room-and-Pillar Mining	2.27	1.91
Load, Haul and Dump	2.00	2.08
Conveyor Haulage to Surface	0.16	0.24
General Operating Costs	0.80	0.49
Mine Ventilation	0.18	0.26
Water Supply and Drainage	0.20	0.20
Administrative Expenses	1.25	0.25
TOTAL	$14.43	$7.35

These are direct operating costs with no provision for interest, depreciation or related financing and management costs. The general operating costs and administrative expenses apply only to the mine.

These are average costs that may vary according to the location and detailed nature of the deposit; therefore, no provision has been made for contingencies. Also, there are some mines with much lower costs than the average costs presented here. Therefore, these should be considered to be on the high side and the objective should be to achieve much lower costs.

4.5.2 CAPITAL COSTS

The costs of preproduction development plant and machinery necessary to exploit the shale deposits by the methods already described have been estimated. These are preliminary estimates based on the average capital costs for metallic and non-metallic mines in Canada and the USA.

Details of the basis of estimate are given in Appendix 1 to this report.

The capital costs are summarized below in Canadian dollars for mid-1982:

	Capital Cost (000)	
	2,000 t/d	20,000 t/d
SURFACE MINING		
Preproduction Development	$ 3,149	$15,458
Water and Drainage System	28	100
Communications System	50	125
Fueling System	75	145
Electrical System	37	1,100
Buildings	1,445	4,992
Mining Equipment	1,976	42,000
Engineering and Construction Management	600	4,100
TOTAL	$ 7,358	$68,020
UNDERGROUND MINING		
Preproduction Development	$ 7,696	$16,722
Hoisting System	624	1,664
Ventilation System	416	1,872
Water and Drainage System	85	562
Communications System	50	104
Fueling System	14	42
Electrical System	700	3,120
Surface Buildings	936	2,808
Mine Equipment	4,576	18,720
Engineering and Construction Management	3,120	7,280
TOTAL	$18,217	$52,894

There is no provision for overhead costs, interest or other indirect capital costs, contingencies, and costs associated with backfilling in underground mining.

4.6 BACKFILLING

The whole matter of backfilling is not included in the above discussion and estimates of costs. However, it is an essential element of any oil shale project and it is being considered here separately, because it is to some extent an indeterminate variable at this time.

The spent shale produced from a retorting process will be a fine, partially calcined material with essentially no moisture content. If, however, the recovery process includes a preconcentration step, then the tailings from that operation will almost

surely be a slurry. These two quite different backfill materials will require quite different methods of handling and disposal.

In a surface operation, the disposal of the waste from the process will present few problems and the cost of delivery to the minesite would be part of the process cost. The waste would probably have to be chemically neutralized in order not to have an effect on the environment.

The disposal of waste in an underground operation will be a different matter. The material will have to be returned underground in an inert and non-contaminating form. This material may be used as part of the mine support system in order to recover more of the resource. It may be necessary to add cement or similar material to stabilize the fill.

Because the quantity of oil removed from a tonne of shale is relatively small, the tonnage of material to be returned is close to that removed and the volume is in fact greater. Apart from finding an area on surface for disposal, this means that the effort in the material handling of the spent shale is almost as great as that for delivering the oil shale to surface. This is especially true when the lateral extent of the operation is much greater than the depth, as is the case with the oil shales in Ontario.

The operating cost for backfilling is estimated to vary from $10/tonne for a 2,000 t/d operation to $3/tonne for a 20,000 t/d operation. This is the cost of uncemented backfill.

The cost of using cemented backfill for a commercial scale operation of 20,000 t/d or more is prohibitive and a limiting factor would be the supply of cement. However, the use of some cemented material is possible in areas of particularly bad ground or in areas where loose fill must be contained.

4.7 CONCLUDING COMMENTS

From the foregoing discussion, it may be concluded that:

1. A mining and processing program on a pilot scale is required in order to determine detailed characteristics of the shales.
2. Open-cast mining is preferred to underground methods.

With respect to open-cast mining, when operating costs are compared, underground mining is at least twice as expensive as an open-cast operation per tonne of rock moved. The major difference in unit operating cost is the amount of development work needed underground: as a rule of thumb, it can be said that 50% of underground operating costs when using bulk mining methods are related to development work. While this does not completely rule out the use of underground methods for mining Ontario oil shales, it does mean that open-cast mining will be carried out whenever possible.

Currently, large, open-cast and underground mines are in operation at production rates ranging from 20,000 to 100,000 t/d. These operations are so efficient from a unit-cost standpoint, that they are treating ores with extremely low recoverable values. Perhaps the best examples are to be found among heap-leach gold mines with recoverable values as low as US $6.50/ton. In terms of overall costs then, the key component is processing rather than mining.

It is anticipated, therefore, that Ontario oil shales will be mined by open-cast rather than underground methods.

5. PROCESS ROUTES FOR ONTARIO OIL SHALES

5.1 GENERAL

The oil shales of Ontario contain vast resources of latent energy that are virtually untapped. This energy, in the form of kerogen can be liberated directly by combustion or indirectly by synfuels production.

The energy and non-energy constituents of an oil shale may be utilized in a number of ways. For example, in an critical energy shortage, combustion of oil shale under fluidized-bed conditions could produce steam for electricity generation. Low-grade calcareous oil shale may be a viable alternative as a supplementary fuel during co-combustion with high-sulphur coal. This would have the effect of reducing sulphur dioxide emissions in conventional coal-fired plants. Limestones or calcareous shales rich in kerogen have been used by the cement industry as solid fuels. These contribute both valuable inorganic constituents to the raw material and to energy savings to the industrial process.

There are two ways to extract energy and byproducts from oil shale:

(1) in-situ or in-place processing, by treating the shale underground without mining, which considerably reduces capital and operating costs; and

(2) surface-plant processing, which involves mining and handling of large quantities of raw shale, crushing and perhaps grinding, followed by particle sizing, in-plant processing, and finally disposal of large quantities of industrial waste in the form of retorted shale or ash.

The many processes, which are either available or under development, are described below in terms of six major routes, each having numerous options in terms of technology implementation or production of end-products. The concepts and technology involved in these routes represent many years, of research and development by the oil-shale, oil and petrochemical, and mining industries. The major routes are:

(1) true in-situ (TIS) retorting;
(2) modified in-situ (MIS) retorting;

(3) conventional surface retorting;
(4) oil-shale beneficiation/surface retorting;
(5) combustion; and
(6) co-combustion.

Each route is described in this chapter; advantages and disadvantages are listed; and an educated guess is taken as to its applicability to the oil shales of Ontario, based on limited characterization studies by WGM and published data collected by the Ontario Geological Survey (OGS).

5.2 RETORTING PARAMETERS

Of the six routes mentioned above, five include retorting, that is, heating of the organic matter, or kerogen, to produce hot hydrocarbon vapours, which are then cooled to yield varying amounts of shale oil and gas.

Many parameters influence retorting. Type, quality and quantity of kerogen, heating rate, and the temperature of retorting are among the main parameters determining the nature and the quantities of evolved hydrocarbons. Other parameters include the granular size of the feed; atmospheric conditions in the vessel; the presence of natural or artificial catalyst(s); the mineralogy and quantity of the inert matter comprising the bulk of the oil shale mass; etc.

At equal organic-carbon content, different types of kerogen retorted by a given process will result in differing oil yields, both qualitatively and quantitatively. The Green River shale of the Western USA, the Irati shale of Brazil and the Albert shale of New Brunswick, to name a few, are said to contain mainly saprolitic (or algal) matter with mainly Type I kerogen (Figure 5-1). Some 60% to 70% of the organic carbon in these shales is converted to hydrocarbon vapours in processes that duplicate Fischer Assay (FA) conditions; namely, inert atmosphere, temperature of about 500°C, and atmospheric pressure. The above-mentioned shales will yield higher amounts of condensable than gaseous hydrocarbons.

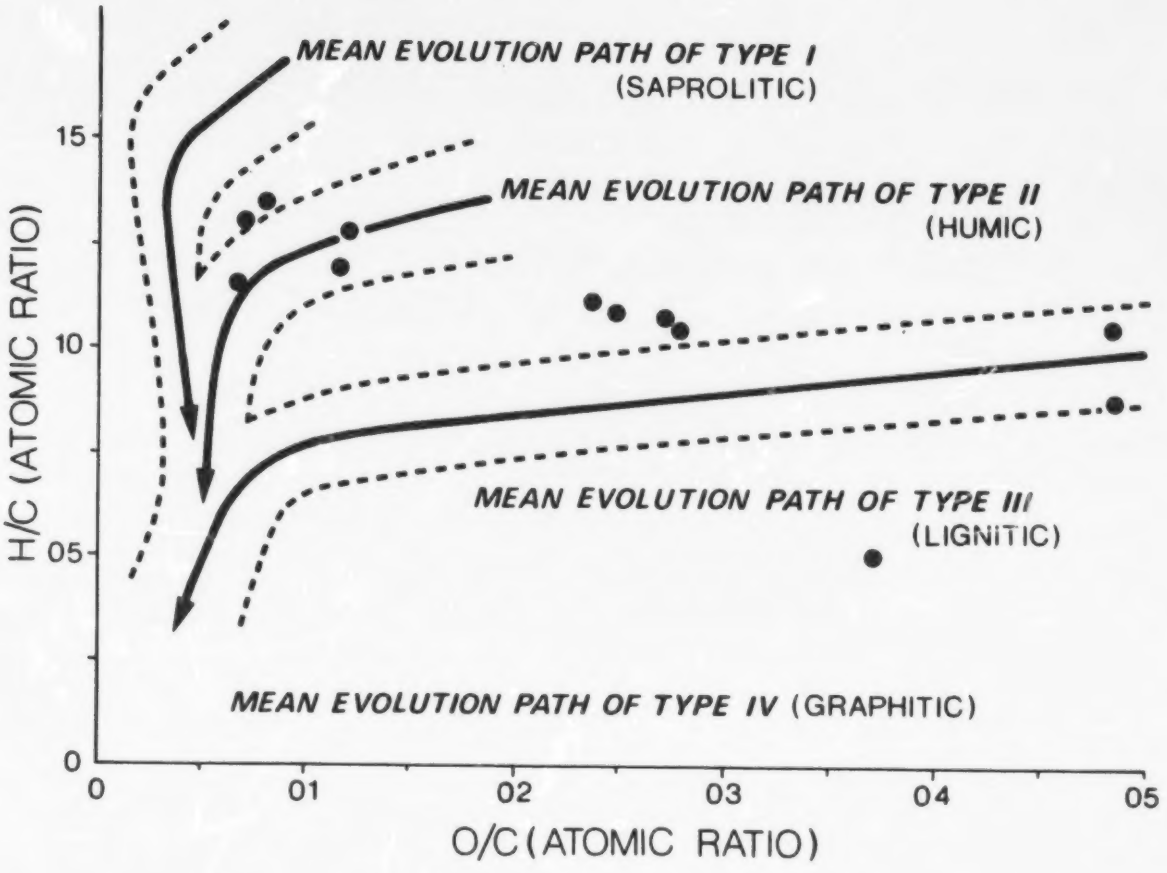

FIGURE 5-1: Location of the elemental analysis of kerogens from "amorphous" organic matter in a Van Krevelen diagram (adapted from Durand 1980).

The Eastern USA shales and the shales of Ontario contain mainly humic matter with a mixture of Types I and II kerogen; less than 40% of the organic carbon of these shales is converted under FA and the liquid yields are lower than for the saprolitic shales. The humic Eastern USA shales have a much lower H : C atomic ratio than the algal Western shales; namely, 1.44 : 1 versus 1.85 : 1.

Shales rich in high H : C atomic ratio kerogen, such as the rich Mahogany Zone of the Green River shale, Colorado, yield in excess of 150 L/t (36 US gal/ton) under FA. These shales have a strong tendency to agglomerate in thick retorting zones, whether the zones are fixed or moving. Gravity or counter-gravity moving-bed retorts that accept high oil yielding shales have mechanical means to prevent agglomeration and/or bridging that may plug a retort. The volume of the kerogen in these shales also tends to increase considerably under heating.

A Colorado shale containing 13 wt% organic carbon will yield in excess of 100 L/t (24 US gal/ton) under FA and will expand by 20% before it reaches the temperature of pyrolysis (480°C). An Eastern USA shale having similar organic carbon content will yield less than 50 L/t (12 US gal/ton) and barely expands under heating.

Combined heating rate and temperature of pyrolysis have a major influence on the decomposition of organic matter. For example, if an oil shale is heated rapidly (within minutes) to 500°C and held at that temperature, it takes 10 minutes to complete retorting. If the same shale is heated as rapidly to only 340°C, the complete reaction may take 100 hours; but if it is heated again as rapidly to 650°C, the complete reaction may take only seconds.

In the case of the Green River shale, USA, it has been shown that a low retorting temperature (400°C) produces more of the desirable paraffin-type than olefin-type hydrocarbons. Intermediate temperature (500°C) produces more olefin- than paraffin-type oil and high temperature (600°C) produces aromatic oil almost exclusively.

Again, on the Green River shale, it has been demonstrated that the heating rate has an influence on both the temperature at which pyrolysis is essentially complete and on the type of hydrocarbons evolved. At a rate of 1°C/min, the reaction is completed at

425°C in 7 hours and the yield is mainly paraffinic oil. At a rate of 100°C/min, the reaction is nearly completed in 6 minutes at 600°C and the yield contains more olefinic oil. At an even faster heating rate, aromatic oil is the main product.

It has also been demonstrated, by various researchers working on different oil shales, that fast heating rates to high temperatures (in excess of 700°C) have different effects on different shales. The calcareous Green River shales of the USA and the calcareous kukersite of the USSR have shown greatly reduced oil yields and increased gas yields when heated quickly to such elevated temperatures (Smith 1975 and Mashin 1982). The same combination may also produce lower quality liquid and gaseous hydrocarbons.

Rapid heating rates to high temperatures of the non-calcareous Eastern USA oil shale have no effect on oil yields, but considerably increase gas yields. Rapid heating of the same shale to moderate temperatures (not exceeding 575°C) considerably increases oil yields, up to 120–140% of FA, and has no apparent affect on gas yields (Margolis 1982). However, the oil produced is of lower quality and has a lower H : C atomic ratio.

Chemical composition of the mineral matter can also affect retorting. Carbonates in a calcareous oil shale will decompose via an endothermic reaction at temperatures in excess of 750°C. For shales containing some 50% carbonates, decomposition can increase heat requirements by more than 20%. For the calcareous kukersite of the USSR, it has been demonstrated that the liberation of calcium oxide can also reduce oil yields (Mashin et al. 1982).

Increased sweep-gas velocity improves the yield and quality of shale oil: it also reduces gas yields by reducing the time period to which the evolved hydrocarbons are subjected to the chemical severity of retorting that produces polymerization (giving heavy oil) and cracking (Allred 1981, Margolis 1982, and Rubel et al. 1983). Counter-current flow of solid and gas, kiln-type vessel and/or fluidized bed technology greatly assist the flushing of hydrocarbon vapours.

Retorting of oil shales in the presence of superheated steam proved to be beneficial to the Scottish oil-shale industry in the 19th century by increasing oil and gas yields and

permitting ammonia production from the spent shale. The results of some experiments on the Green River and the Eastern USA shale have also shown increased yields (Allred 1981, Margolis 1982, and Rubel et al. 1983), but the results of other experiments have shown no increase (Carter and Taulbee 1984).

Retorting in the presence of hydrogen results in spectacular increases in oil and gas yields and organic carbon conversion, particularly for shales with a low H : C atomic ratio. Increases of up to three times have been achieved in bench-scale apparatus (Jensen et al. 1953, TRW 1979, and Furimsky et al. 1983).

Closely-sized material gives better oil yields. Pieces with the largest dimensions are slowest to retort. The interior of the larger particles heats up at a slower rate; thus the hydrocarbons require more time to evolve and escape, and are gradually exposed to higher temperatures causing lower oil yields. Retort systems that accept fine particles allow for the uniform flow of gases and provide slightly higher oil yields than FA. Systems utilizing extremely fine particles cause severe contamination of oil products, making them less acceptable as refinery feed.

The thickness of the shale bed in a process affects retorting. Thin horizontal beds, such as the circular travelling grate (Section 6.3.2) and the Kiviter process in the Soviet Union, experience fewer operating problems, such as bridging, coking, agglomeration, and erratic or awkward passage of the feed through the retort; problems that have been experienced in many continuous flow, vertical retorting systems (Mashin et al. 1982, and Dohnt 1980). The Union Oil Type "B" retort uses upward solid-pumping to load rich, raw shale and reduce agglomeration and bridging. The pumps vibrate the retorting bed and break bridging.

Reducing the internal static pressure within shale fragments assists the evolved hydrocarbons to escape from within the fragments. Static pressure reduction is achieved by placing the retorting front as close as possible to the top in vertical operation retort. High rock pressure on retorting rock fragments augments reaction time within the fragment and promotes polymerization (to heavier oil), cracking (higher gas yields) and coking (causing agglomeration). All three effects can curtail the efficacy of the process. In high yielding, 167 L/t (40 US gal/ton), Green River

shale, the critical contact pressure is 6.9 kPa (1.0 psig); in medium high yielding shale, 125 L/t (30 US gal/ton), the critical pressure is 31.0 kPa (4.5 psig). The higher the critical pressure, the higher can be the column of solid above the retorting zone. The height of the column has a limit; intense rock pressure will break rock fragments, increase fines, and reduce the flow of flushing fluid.

The Union Type 'B' retort has an inverse cone shape that reduces rock pressure by expanding the horizontal section of the bed of the upward-moving shale. The horizontally expanding bed also reduces agglomeration and bridging, and compensates for rock volume expansion (Dohnt 1980). Horizontal retorts using a circulating grate or kiln-type vessel have a definite advantage in reducing internal static pressure.

The above parameters have not been tested on the shales of Ontario. However, FA and pyroprobe analytical results shown in OGS open file reports may indicate that yields are reduced by the combination of fast heating rate and high temperature of pyrolysis. Hydrocarbon yields for 25 samples averaged 5.6% by weight under FA (oil and gas plus loss) versus 3.5% C by weight in methane equivalent or 4.7% CH_4 under pyroprobe work. In FA, a 100 g sample of crushed (-6.5 mm) shale is heated to 500°C in 50 minutes; in pyroprobe analyses, 5–50 mg of material pulverized to 75 µm, are heated to 900°C in 10 minutes.

5.3 TRUE IN-SITU ROUTE

5.3.1 DESCRIPTION

In the TIS route (Figure 5-2), pyrolysis takes place within the confines of the shale formation, underground and without the mining and removal of any rock; an important economic factor. Shales being naturally semi-pervious to impervious, the first step consists of creating artificial permeability by fracturing, using either explosive or hydrostatic pressure through boreholes, in a manner similar to enhanced recovery methods used by the oil industry.

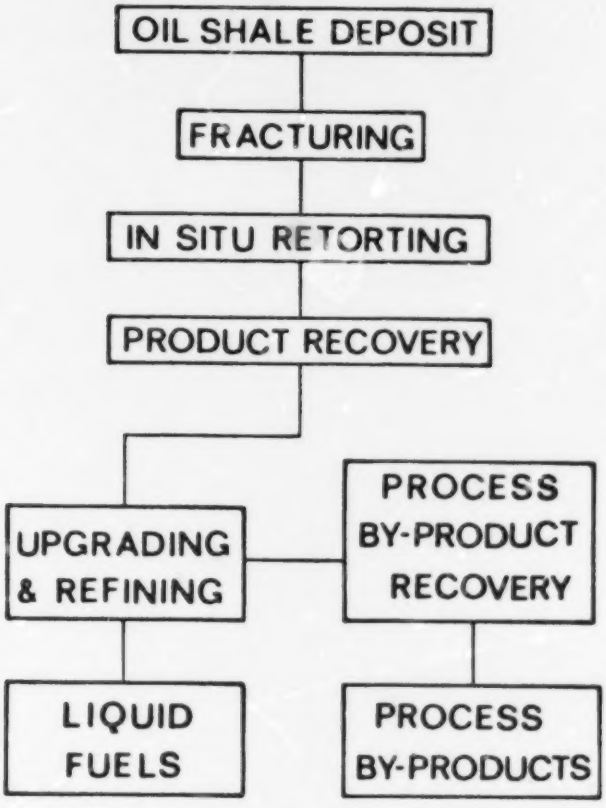

FIGURE 5-2: True In-Situ Route (source: Ward 1984).

Inducing voids and rubblization by fracturing requires the surrounding material to be compressed and/or lifted without creating openings or leaks to the surface, the rubble must be sealed to prevent the escape of hydrocarbons. Material surrounding the blast zone must be sufficiently competent to prevent closure of the voids. Blasting may lift the overburden, partially break and move bedrock, and translate and rotate fragments to prevent closing of voids and to ensure porosity and permeability.

Bioleaching, through borehole injection, to dissolve carbonates by microbially-produced sulphuric acid, has frequently been suggested as a way of creating porosity and permeability; however, this technique has not been tested in the field.

In-situ pyrolysis requires the transmission of heat, through the circulation of large quantities of hot gases, which are generally obtained from the combustion of a portion of the organic matter. Heat decomposes the kerogen and creates hot hydrocarbon gases, some of which condense underground. The hydrocarbons are recovered through production wells.

In-situ dielectric heating has been suggested for TIS retorting without rubblizing. The technique has been under development since 1976 by the IIT Research Institute. Dielectric heating brings the shale to retorting temperature and vaporizes the kerogen. The evolved hydrocarbon vapours should generate sufficient internal pressure to fracture the surrounding rock mass, and create the permeability required for the free circulation of vapours and liquid to production wells. The method was field tested in 1981, in a cubic metre of in-situ shale in the face of a trench. As no results have been published, we suspect that they were inconclusive or negative, and that the project was abandoned.

5.3.1.1 Shallow In-Situ Retorting

The most advanced TIS process is called LOFRECO, for LOw FRont End COsts (Figure 5-3). It was developed for relatively thin and shallow oil-shale beds overlain by impervious waste rock or overburden. The developer is Geokinetics Inc. aided by significant amounts of funding from the United States Department of Energy.

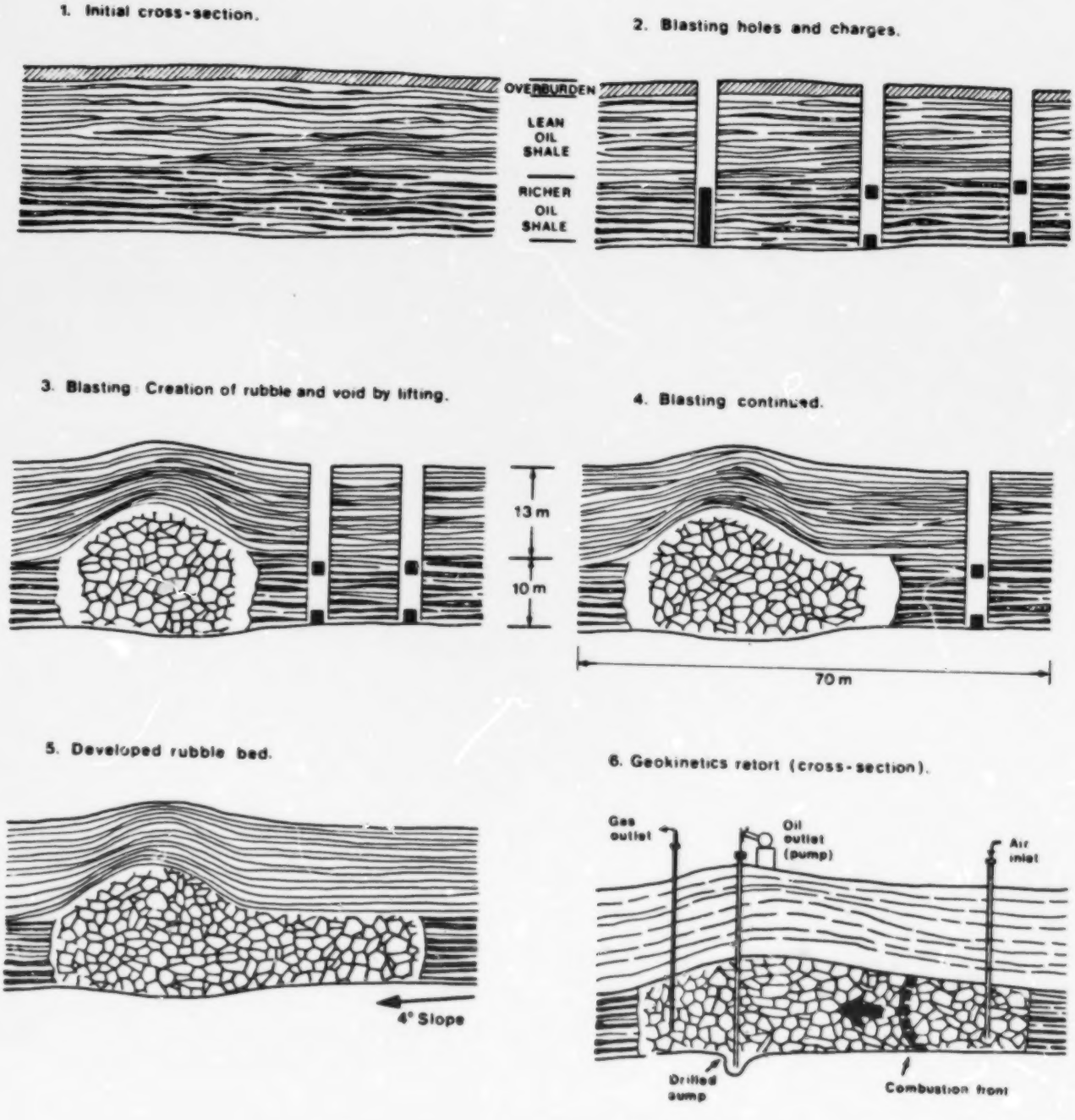

FIGURE 5-3: Schematic development of the Geokinetics shallow true in-situ retort (adapted from Lekas 1981).

The first stage of the process consists of drilling a pattern of blast holes, through the overburden, to the bottom of the unit to be retorted. The holes are loaded with explosives and fired in a planned sequence. The blast is designed to develop a sealed fragmented mass of oil shale (the retort), with high permeability and a gently sloping floor. Artificial permeability is created by fragmentation and displacement of the shale. The expansion results in lifting the overburden, which produces a small surface uplift. Fracturing of the overburden must be kept to a minimum to prevent the escape of hydrocarbon vapours.

The second stage consists of drilling a series of air-injection holes in the fragmented mass at one end and a series of off-gas holes at the other end. Intermediate oil-production holes are drilled through the mass, to a sump drilled in the sloped bottom.

The shale is then ignited at the air-injection wells. A burning front is established and maintained for the full thickness and width of the fragmented mass, and pushed horizontally toward the off-gas wells at the other end. Hot combustion gases decompose the kerogen and hot, gaseous hydrocarbons are evolved.

Most of the hydrocarbons condense some distance from the retorting front, drain to the floor, and flow along the sloping bottom to the oil-production wells. As the burning front moves toward the off-gas wells, it combusts the residual coke left in the retorted shale to provide retorting heat. The combustion gas and the non-condensed portion of the evolved hydrocarbons are recovered at the off-gas wells.

The LOFRECO process was tested on Utah oil shales from 1975 to 1984. The size of the retorts has reached commercial dimensions. The oil shales tested consist of a lower 10 m thick rich unit (100 to 125 L/t or 24 to 30 US gal/ton by FA) overlain by a leaner (40 to 45 L/t or 9.5 to 10.8 US gal/ton), 11 m thick unit and 2 m of barren overburden. Two commercial size retorts covering 4,000 m^2 of lands and containing approximately 6,500 m^3 (40,885 bbl) of in-situ shale oil equivalent were processed. The burning front was pushed forward at a rate of 0.3 m/day. Dependent on air injection rate, some 16 to 32 m^3 (101 to 201 bbl) per day of oil were produced per retort. Some 95% of the produced condensable hydrocarbon vapour was recovered as an oil–water emulsion. The collected low calorific off-gas was combustible and had a

heating value of 2.5–6.5 MJ/m^3. The overall recovery of shale oil was at 35% of FA, assuming that no shale oil was produced from the overlying lean oil shale.

In nine years of testing, the company has produced in excess of 5,000 m^3 (31,450 bbl) of shale oil. Most of the oil has been marketed, without nitrogen removal, to local refineries. Part of it was blended with conventional feedstock and run through a fractionation column and catalytic cracker. The gasoline product met refinery specifications, but the diesel fuel failed the spot test due to the presence of a fine precipitate. Another part was blended directly with a N°. 5 fuel oil product and sold to large industrial consumers, to verify that large quantities of shale oil could be sold without extensive upgrading.

According to Geokinetics, capital expenditure for a project capable of producing 800 m^3 (5,032 bbl) per day of shale oil from shale yielding 75–100 L/t (18–24 US gal/ton) under FA would be in the order of US $25 million (1981 dollars). The shale should be shallow, no more than 30 m to the bottom.

5.3.1.2 Moderate to Deep In-Situ Retorting

Moderate (30–150 m) and deep (in excess of 150 m) TIS retorting was tried unsuccessfully by the Laramie Technology Center and Talley Energy Systems within Wyoming oil shale, and by the Dow Chemical Company within the deep Antrim Shale of Michigan. All three groups failed in their attempts to create sufficient artificial permeability for the effective circulation of fluids in gaseous form.

5.3.1.3 Advantages and Disadvantages

The apparent advantages of true in-situ retorting are:

(1) reduction of capital costs by eliminating the development of a mine and the construction of a surface retorting plant;

(2) minimal surface disturbance by lifting or subsidence;

(3) low operating cost (there is no handling and no haulage of large quantities of rock);

(4) no solid waste disposal;

(5) low water requirements (none if water produced from retorting can be used); and

(6) technology amenable to medium-yield shale (75–100 L/t or 18–24 US gal/ton under FA).

Some of the disadvantages include:

(1) difficulty of inducing the required permeability at depths in excess of 30 m;

(2) high drilling costs;

(3) difficulty in ensuring that the retort is sealed;

(4) flooding of the retort by aquifers, or difficulty in controlling flooding;

(5) difficulty of controlling combustion;

(6) low recovery efficiency (field tests generally below 40% of FA oil and gas yields);

(7) not adaptable to hydrogen retorting for shales having a low organic carbon conversion;

(8) possible contamination of subcrop and aquifers by release of artificially produced chemical compounds; and

(9) no recovery of potential mineral or industrial byproducts.

5.3.2 ANALYSIS

The oil shales of Ontario occur in sub-horizontal uniform units, that barely outcrop, but underlie hundreds of square kilometres of land. Thicknesses range from 2 m to more than 15 m for those units that yield in excess of 20 L/t (4.8 US gal/ton) under FA. The shales have low yields from FA, and are generally overlain by wet overburden, with aquifers frequently present at the overburden/bedrock interface.

Shallow TIS retorting has little potential in Ontario, mainly because:

1. The recovery of the latent energy is expected to be low. Well under 20% of total organic carbon would be converted and/or recovered in the form of hydrocarbon fluids (or less than 40% of FA yields).
2. It is not adaptable to the introduction of hydrogen to increase organic carbon conversion.
3. The top of the known high-grade shallow shales is at the overburden/bedrock interface, where aquifers usually occur. These aquifers would flood retorts, preventing ignition and combustion of the shale. In the event that the retort could be dewatered, the risk of polluting aquifers or the overburden may outweigh any economic benefits.

Open-pit and surface retorting should convert at least 40% of the total organic carbon to useable hydrocarbon vapours and is more attractive than shallow TIS retorting.

The potential for moderate to deep TIS retorting is remote, because of the added difficulty in creating adequate permeability at greater depth and the low anticipated recovery.

In light of the above, in-situ retorting is considered an unlikely processing route for the shales of Ontario.

5.4 MODIFIED IN-SITU ROUTE

5.4.1 MODIFIED IN-SITU RETORTING

Creating in-situ permeability in moderate to deep oil shales, through boreholes, has proven to be technically difficult and an adequate solution has yet to be found.

To circumvent the problem, developers are working on the MIS route (Figure 5-4), in which a fixed-bed chemical reactor is built underground out of the oil shale bed, and contained by 'unbroken' shale rock that creates the wall of the reactor. It is a large batch process that should provide controlled and reproducible permeability. The characteristics and geometry of the fragmented mass and of the wall rock allow for safe, efficient, in-place processing for hydrocarbon recovery, and leaves the in-situ spent shale in its most innocuous and inobtrusive state, both environmentally and aesthetically (Figure 5-5).

In this method, 20–40% by volume of the in-situ shale rock is first removed by underground mining to create rooms (voids) separated by large temporary pillars. The mined shale is hauled to surface and, if it is rich in kerogen, retorted in surface plants. If it is not, it is sent to waste rock dump piles. Holes are drilled in the shale between the rooms, so that explosives can be placed to break, expand and displace large parts of the temporary pillars into the voids, to create filled artificial retorts. These are provided with the needed induced voids for effective flow of processing gases and

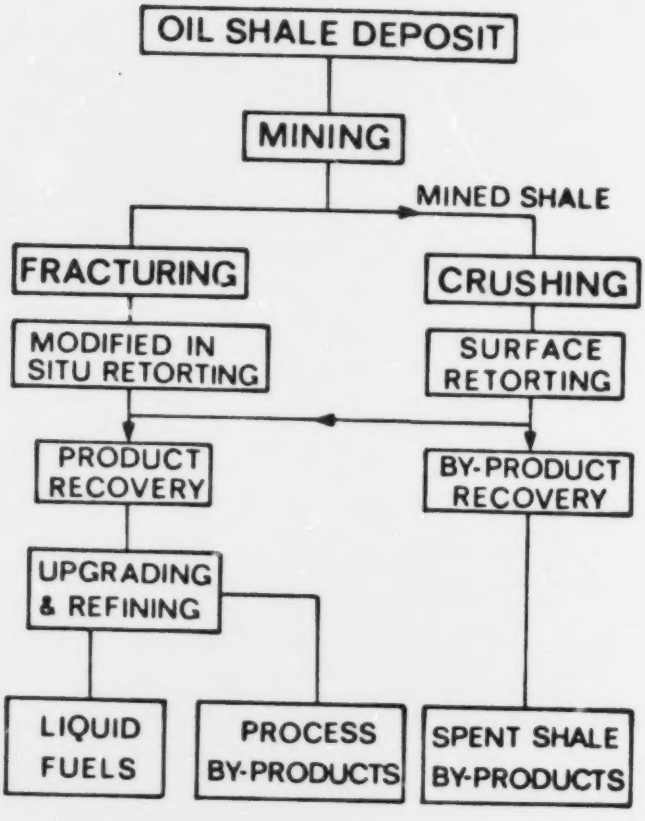

FIGURE 5-4: Modified In-Situ Route (source: Ward 1984).

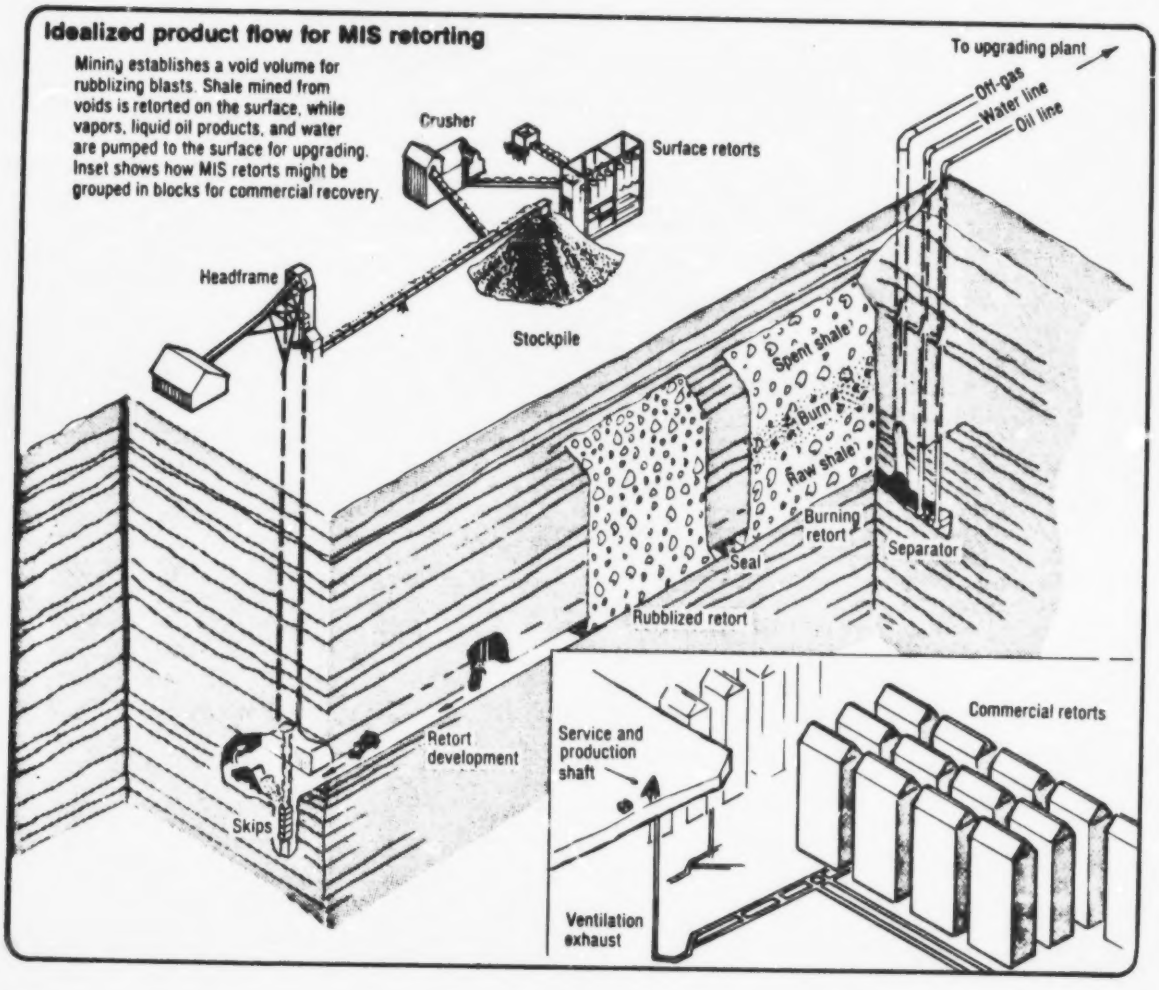

FIGURE 5-5: Idealized product flow for Rio Blanco modified in-situ (MIS) retorting approach (source: Engineering and Mining Journal, June 1981).

products. Blasting occurs after openings to the man-made voids have been sealed. After blasting or rubblization, the filled retorts are fitted with a means of introducing combustible matter to initiate retorting, and to withdraw the liquids and gases produced. The rubbled mass is then ignited by heating, to self-ignition temperature. At this point, the organic matter reacts with injected oxygen and generates the energy needed to establish and sustain a retorting front.

During retorting, the rubbled bed comprises five distinct zones (Figure 5-6):

(1) a gas preheating zone, in which sensible heat in the spent shale is transferred to the incoming combustible gas and/or oxygen;

(2) a combustion zone, where oxygen and the preheated gas react with residual char in the retorted shale to generate the retorting heat;

(3) a retorting zone, in which the hot gas leaving the combustion zone heats the downstream shale to pyrolysis temperature and breaks down the kerogen into hydrocarbon vapours and residual char;

(4) a preheating or preparation zone, where the sensible heat of the evolved vapours preheat the raw shale and where condensable hydrocarbons turn to liquid phase; and

(5) a cooling zone, where the shale oil/chemical water emulsion is collected in sumps at the bottom of the retort and pumped to the surface, and where the non-condensable are extracted through off-gas wells.

There are no MIS retorting projects in operation, and most research and development carried out on MIS has been for the thick and high yielding Mahogany Zone of the Green River shale, and more particularly for the Cathedral Bluffs and Rio Blanco projects located in the State of Colorado. The projects, mothballed in late 1981 – early 1982, were to produce 15,000 m^3 (94,350 bbl) per day and 8,000 m^3 (50,320 bbl) per day, respectively, of shale oil by the early 1990s. Each company has spent, to the end of 1981, in excess of US $100 million in research and development alone.

The proposed Cathedral Bluff development involved conventional load–haul–dump or conveyor-assisted mining on three levels to produce 15–25% void by volume. The project called for the development of 120 retorts per year, requiring the removal of 55,000 t/d for void making and for other mine development. The retorts would be 80 m high and have a 50 m^2 horizontal section. To achieve the planned production of 8,000 m^3 (50,320 bbl) per day would require the simultaneous burning of 96 of these

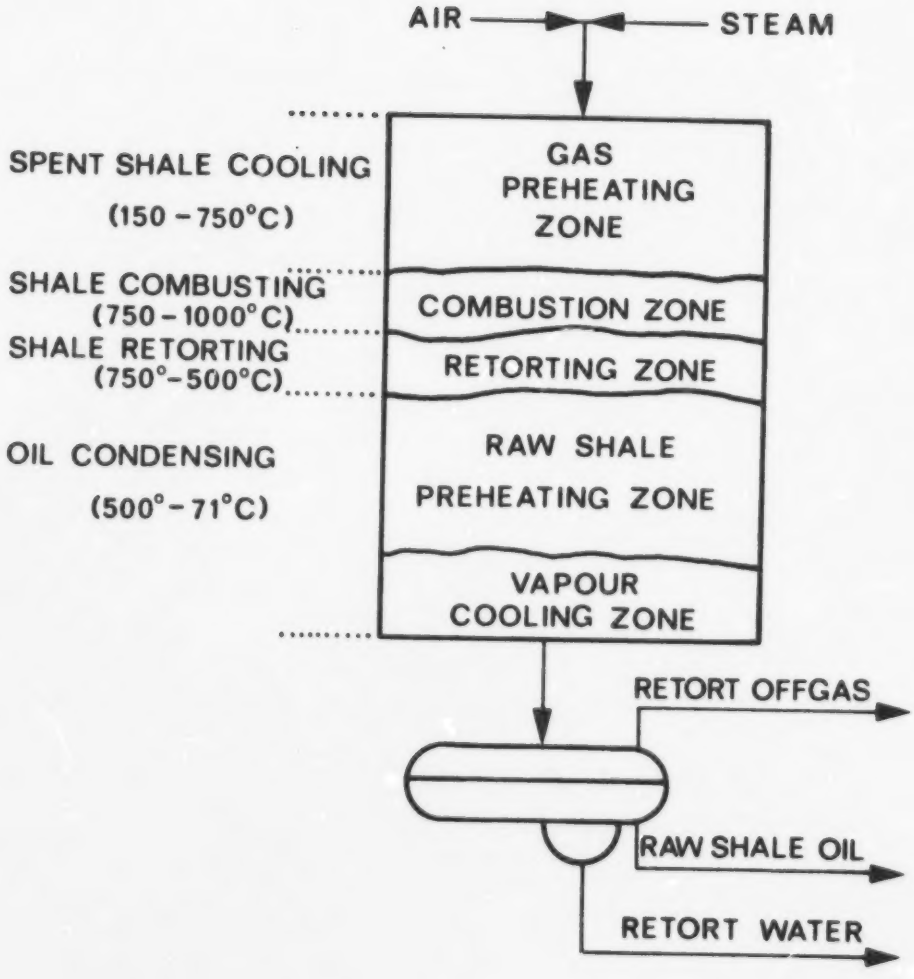

FIGURE 5-6: The zones of an operating modified in-situ (MIS) retort.

retorts. The underground operation is comparable to a controlled burning of 25 to 30 city blocks, each block composed of 30-storey buildings.

The Cathedral Bluffs planned MIS retorting of 80–85% of the 88 m thick section of the Mahogany Zone, versus the 50% extraction of a section 18 m thick by room-and-pillar and conventional surface retorting. However, commercial size field tests conducted in retorts 50 m high with an area of 85 m^2 gave poor recovery at only 40% of FA for the rubblized material.

Rio Blanco proposed the development of retorts 212 m high through mining of a single level for 30–40% void preparation and appropriate sublevels for intercepting and channelling water where aquifers are encountered. Tests in pilot retorts have indicated a recovery of 60% of FA for the rubblized material. This amounts to only one-third recovery of the organic carbon present in the raw shale.

Advantages and disadvantages of the MIS route are similar to those of the TIS route, except that their importance is intermediate between TIS and the conventional surface retorting route.

The apparent advantages of MIS retorting are:

1. Capital costs are reduced by reducing the size of the mine to be developed and of the surface retorting plant to be constructed.
2. Minimal surface disturbance is created by subsidence, the retorts are still full of spent shale, and access passages can be backfilled.
3. Operating costs are lower than exclusive surface retorting, as only 20–40% of the oil shale mass must be handled and hauled to surface.
4. Surficial solid waste disposal is considerably reduced, especially if backfilling of the access passages is implemented.
5. No water is required for the underground retorts and only moderate amounts for the surface plants.
6. In the long-term, it may be economically feasible to medium- to high-yielding shale (100–125 L/t or 24–30 US gal/ton under FA).
7. Recovery of potential mineral or industrial byproducts from the mined shale is feasible.

Some of the disadvantages include:

1. In excess of 40% of the shale unit to be retorted is left untouched to create the walls of the MIS retorts.
2. 20% to 40% of the rock mined to create artificial voids must be brought to surface retorting facilities.
3. There is difficulty in obtaining constant adequate rubblization.
4. There is difficulty in ensuring that the retort is truly sealed after blasting.
5. It is difficult to control flooding by aquifers, although possible at considerably increased operating cost.
6. It is difficult to control combustion.
7. Recovery efficiency is low: results of field tests generally ranged between 40% and 60% of FA oil and gas yields.
8. Contamination of subcrop and aquifers could be a major problem.

5.4.2 ANALYSIS

For the deeper sub-horizontal oil shales of Ontario with thicknesses in excess of 10 m (Kettle Point and Long Rapids Formations), it should be technically feasible to prepare MIS retorts in the generally competent rock. The OGS descriptive core logs do not indicate the presence of permeable concordant lithologies within the oil shale beds and aquifers would therefore be associated with discordant structures and should be controllable.

However, since the shales of Ontario have low-yield under FA (less than 60 L/t or 14 US gal/ton) over mineable widths, MIS retorting is believed to be of limited potential and is considered to be an unlikely processing route, especially because:

1. The recovery of the latent energy is expected to be low. Well under 25% of total organic carbon would be converted and/or recovered in the form of liquid or gaseous hydrocarbons (or less than 60% of FA yields).
2. Hydrogen retorting to increase organic carbon conversion to liquid yields would not be practical, because of foreseeable difficulties in maintaining a pressurized environment in the retort.

5.5 CONVENTIONAL ROUTE

5.5.1 DESCRIPTION

The expression 'conventional route' applies to the bulk of the research and development activities carried out, in Western Hemisphere countries, toward the construction of economic industrial surface-retorting processes. The term 'conventional', does not apply to well established industrial processes; it does apply to the decades of monumental efforts, and to the millions of dollars spent by governments and industries toward the development of large-scale efficient processes.

Oil-shale recovery by the 'conventional route' (Figure 5-7) is the resolution of two major tasks: material handling and processing.

The two tasks require:

(1) mining of the oil shale by open-cast or underground mining methods;
(2) haulage of the mined shale to a surface plant;
(3) crushing and screening to prepare the retort feed;
(4) retorting;
(5) recovery and upgrading of the shale oil to synthetic crude oil and, eventually, conversion of the off-gases to hydrogen or synthesis gas;
(6) recovery of mineral byproducts; and
(7) disposal of large quantities of processed shale that may have been retorted (spent shale) or retorted and combusted (ash).

5.5.1.1 Mining and Haulage

The Ontario oil shales, described and reviewed in Chapter 3, occur in sub-horizontal units that only outcrop over a few square kilometres, but may underlie thousands of square kilometres. Thicknesses vary from 2 to 40 m and the shales are overlain by waste rock and/or overburden that ranges from 0 m to in excess of 200 m. The shales are amenable to open-cast and underground operations, with open-cast being favoured (see Chapter 4). The choice of a mining method is governed by the such parameters as:

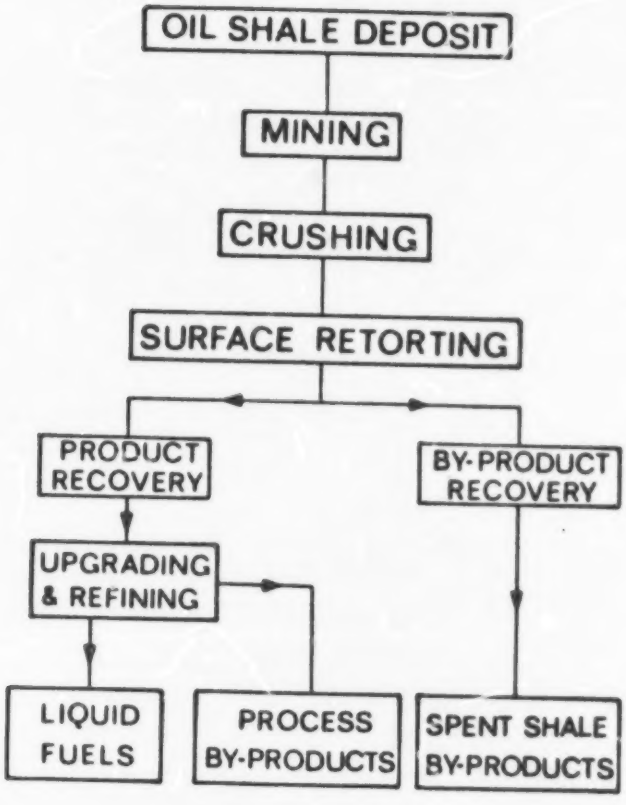

FIGURE 5-7: Conventional Route (source: Ward 1984).

— thickness of the overburden;
— attitude and mechanical properties of the oil shales and of the overlying waste; and
— economic constraints.

Once broken, the mined shale may go through a first stage of crushing before being hauled to the surface processing plant that may be located up to 10 km away from the mine. Haulage may be carried out by one or more means, such as: conveying, trucking, rail, slurry pipe, and load–haul–dump vehicles.

5.5.1.2 Feed Sizing

Sizing of feed ensures proper circulation of solids, evolved hydrocarbons and flushing fluids within the confine of the retort. Some retorts require a closely-sized feed of coarse materials without fines, while others need only fines.

Vertical retorts with gravity- or counter-gravity-moving bed need a closely-sized coarse (from about 1.0 to more than 10 cm) feed with little fines. The coarse feed increases retention time and process severity of retorting. The removal of the fines also reduces the negative effects of time and severity by increasing the sweep-gas velocity of the flushing fluid. Kiln-type rotating vessels tolerate the introduction of fines (less than 1 cm) in the feed. Some fluidized bed retorts require material finer than 0.6 cm for proper entrainment by the fluidizing medium. For flash retorting, the feed must be finer than 75 µm.

Feed sizing may consist mainly of secondary-stage crushing with screening for the coarser feed retorts, and of stage grinding, sieving and/or cycloning for fine-feed retorts such as flash pyrolysis.

Crushing is influenced by rock parameters, such as texture and structure, inorganic mineral contents, and quality and quantity of the organic matter. Shale having hydrogen-rich kerogen has a strong plastic tendency, and will deform under shearing and compression. Barren and low oil-yielding shales are tough, friable, laminated rocks that tend to break along bedding planes and give a slabby rather than cubical product. Slabs have a tendency to orient themselves in a thick moving-bed retort and

to close the permeability of the retorting mass. The organic matter of the high-yielding shales is continuous and surrounds the mineral matter: it tends to blend and flow and will prevent breaking along bedding planes. Cobbles and blocks from rich shales frequently aggregate under compaction and shearing and plug the crusher. Impact crushers give a larger proportion of cubes and are preferred to gyratory, jaw, or toothed-roll crushers. They also produce more fines and dust, are noisier and are more expensive to maintain. Toothed-rolls and jaw crushers make few fines and their product is more suitable for coarse-feed retorts.

5.5.1.3 Retorting

Retorting is the decomposition or destructive distillation of substance by the action of heat in a vessel. In surface retorting, the shale is heated to a temperature ranging from 400°C to 650°C, the kerogen is decomposed, and hydrocarbon vapours are evolved and removed. Some of the vapours may condense to shale oil within the retort; however, most are flushed out as hot gases and condensable at various temperatures. Retorting products include raw shale oil, raw shale gas, chemical water, and spent shale with residual carbon (or coke), or combusted shale without the coke.

The quality and quantity of retorting products depend on retorting parameters and processes. The main retorting parameters are described in Section 5.2, above. Many retorting processes have been devised since the early days of oil shale development in the 17th century. We have selected 18 of the most prominent retorting systems and have described them in some detail in Chapter 6.

5.5.1.4 Hydrocarbon Recovery and Upgrading to Synthetic Crude Oil

Retorting processes give raw shale oils and gases that are highly variable in chemical and physical properties. Shale oils from inert atmosphere retorting are heavy and can be viscous with high pour points. They have low hydrogen content, and have moderate to high contents in sulphur, nitrogen, particulates, and undesirable trace elements. Shale oils also contain large fractions of unsaturated and aromatic compounds that tend to form gums during storage and make them unstable. Depending on the mode of application of retorting heat, shale gases may be of low or high heating values and will

have substantial amounts of nitrogen, sulphur, carbon dioxide, carbon monoxide, and particulates.

Raw shale oils from Western USA shales are normally not transportable, but the raw oils from Eastern USA shales generally are. Shale oil must still however be upgraded prior to delivery to conventional refineries or to industrial consumers.

Two upgrading modes are possible:

1) **Carbon Rejection Mode** – this low cost method, also known as coking, cracks the raw shale oil into lighter oils of lower pour points and generates a coke of low market value; and
2) **Hydrogen Addition Mode** – these more expensive methods, variously known as hydrotreating or hydrogenation require the addition of hydrogen but may considerably improve the quality and slate of the final products.

In regard to raw shale oil, two market options are usually considered:

(1) minimized upgrading, with the majority of the shale oil being marketed as heavy crude or N°. 6 fuel oil; and
(2) maximized upgrading, to the point where the raw shale oil is marketable as a N°. 2 fuel oil or is a suitable conventional refinery feed that will eventually produce gasoline, jet fuel, home-heating oil, and petrochemical feedstocks.

For Canada, the second option is most likely. Large reserves of heavy crude oils exist and large quantities can be produced in the long-term. Furthermore, the market for heavy crude is declining and there is a growing trend to eliminate the use of heavy heating oil.

To our knowledge, no shale oil produced from Ontario shales has been subjected to intensive characterization and upgrading testing. However, the shales of Ontario are similar to the Eastern USA shales and it may be inferred that shale oil treatment processes developed for the latter may work for those of Ontario. The methods proposed for the upgrading of shale oil are those commonly used in the petroleum refining industry, but modified to accept a feed with much different physical and chemical characteristics.

A basic treatment for raw shale oil and gas could be similar to that of the HYTORT process (Section 6.4.6). The treatment, described in Vyas et al. (1981), incorporates:

1. A gas-liquid separation system, where the hot evolved hydrocarbons are passed through a cyclone for early removal of entrained oil and water droplets and shale fines, then are sent to a coaslescer and finally to an electrostatic precipitator. The oil passes through desalting and hydrotreating systems, and is finally sent for storage in settling tanks.
2. A gas cooling and cleaning system, where the gas from the separation system passes through a knockout drum, compressed to 3,600 kPa (522 psig), is sent to an ammonia recovery system, and then through an acid gas-removal system, where carbon dioxide and hydrogen sulphide are reduced considerably, giving a sweet gas.
3. A cryogenic separation unit, where the sweet gas is cooled, to first remove water and heavy hydrocarbons by condensation. The remaining cooled gas passes through aromatic filters to remove residual aromatics, carbon dioxide, hydrogen sulphide, and steam. Further cryogenic separation will produce a hydrogen-rich gas stream and a methane-rich gas stream.
4. Additional hydrogen is made through a conventional steam reformer that transforms heavier hydrocarbon gas and methane gas into a hydrogen, carbon monoxide and carbon dioxide stream.
5. The hydrogen–sulphide-rich gas produced by the acid gas removal system in 2. is sent to a sulphur recovery system consisting of a three-stage Claus unit and a SCOT tail-gas clean-up unit.

The properties of raw and hydrotreated oils from Eastern USA shales are discussed in further detail in Chapter 8 of this report.

Raw shale oil from Eastern USA shale, when upgraded and hydrotreated, can be made to produce a refinable synthetic crude oil. The end-products could be variable quantities of N°. 6 and/or N°. 2 fuel oil, jet fuel, gas oil, naphtha, residual oil, coke, elemental sulphur, ammonia, etc.

5.5.1.5 Mineral Byproducts Recovery

Fresh shales contain a suite of major oxides and minor and trace elements that, after retorting, may end up in one or more of retorted shale, combusted shale, wastes produced from upgrading shale oil and gas, and/or ash from gas clean-up. Some of these oxides and elements could be subjected to an artificial primary concentration during retorting by preferentially ending in one of the retorting products. Secondary

concentration could be effected by beneficiating retort products or extracting oxides and metals by accepted mineral industry methods, such as roasting and acid leaching, stage solvent extraction, reverse osmosis, etc.

Some metals with recovery potential and probable range of contents in fresh Eastern USA and Ontario shales are:

Al.....	3–10%
Fe	1–10%
Co	10–60 ppm
Ni.....	10–200 ppm
Mo	10–200 ppm
U	10–100 ppm
Zn	10–125 ppm
Cr.....	30–300 ppm
Mn	100–350 ppm
Nb	10–20 ppm
V.....	10–600 ppm

Of the mentioned elements Al, Fe, Mo, Zn, Cr, and V have the greatest potential. Furthermore, fresh, spent or combusted calcareous shales may have potential as raw products in the cement industry. The recovery of byproducts metals, oxides and minerals, if feasible, could considerably improve the economics of an oil shale industry. This subject is discussed in more detail in Chapter 8.

5.5.1.6 Disposal of Spent Shale

Spent or combusted shale is the major product of an oil-shale industry in terms of weight and volume. Spent shale is a solid that may be neutral to alkaline, grey to black, and may occupy a volume 20% to 30% greater than the in-situ raw shale. It may be disposed of on the surface or underground. The environmental impact associated with spent shale disposal is discussed in Chapter 9.

5.5.2 ANALYSIS

The advantages of the conventional route over the TIS and MIS routes are:

1. An open-cast operation could mine up to 100% of good grade oil shale, while underground mining could mine up to 75% of the same shale.

2. Good control of retorting conditions will give oil yield at least equal to FA, while hydrogen retorting is capable of yields in excess of 300% of FA.
3. In excess of 80% of the organic carbon may be converted to shale oil.
4. Combustion of the spent shale recovers up to 95% of the residual carbon.
5. A surface retort is a sealed environment and contamination of surrounding air, surface and ground water and soil is less likely.
6. Potential industrial minerals and byproducts could be recovered.

The disadvantages are:

1. Capital and operating costs are high, compared to the TIS and MIS routes and possibly the beneficiation route.
2. Surface disturbance must be minimized by proper mining and land reclamations techniques.
3. Particle-size requirements for many of the retort feeds mean that in some cases only 80% of the mined shale is utilized.
4. Large quantities of waste must be disposed of in an environmentally acceptable manner.
5. Process water requirements are high and the process effluent must be cleaned of pollutants before being released to the environment.

Ontario oil shales have a low atomic H : C ratio and have low yields from FA. Optimization of these yields will be a critical factor in the decision to develop an oil shale industry in Ontario.

Since retorting in the presence of hydrogen and superheated steam have been shown to increase oil yields to up to 300% of FA (Furimsky 1983; HYCRUDE 1984), it appears that a combination of mining and retorting in a surface plant may be a likely route to produce shale oil.

5.6 BENEFICIATION ROUTE

5.6.1 DESCRIPTION

5.6.1.1 Concept

Oil shales are layered sedimentary rocks in which some 5 wt% to more than 35 wt% of kerogen is mixed with 95–65 wt% inorganic mineral matter. The shales are laminated and may have a varved, thinly bedded or massive appearance. The kerogen is fine-grained and may be disseminated uniformly throughout the rock (Ontario and Eastern USA shales) or preferentially located in some strata, resulting in alternating layers lean and rich in kerogen (New Brunswick, Colorado, and Australian shales).

Retorting by the conventional route, reviewed in the previous section, requires heating all of the mined shale feed, which consists of small amounts of the oil- and gas-producing kerogen and large amounts of barren inorganic mineral matter.

Processing all of the run-of-mine feed requires large retorts, having high capital and operating costs. Large amounts of heat are also required to raise the temperature of the entire mass to the retorting temperature. Attempts have been made in the last 50 years to reduce capital and operating costs and heat requirements, by upgrading the retort feed via some of the mineral beneficiation techniques used by the mining industry. One beneficiation route, which applies to the concentration of kerogen by grinding and flotation methods, is illustrated in Figure 5-8. Other methods and combinations of methods are also possible.

Cobbing of banded deposits and concentration, followed by crushing, grinding and flotation of disseminated ores, are vital to the base metal, precious metal, iron ore, and industrial mineral industries in upgrading low-grade and/or low-quality deposits to a higher grade and better quality feed for final processing.

The development of innovative mineral processing technology by metallurgists now permits the extraction and recovery of metal from ores with grades as low as 1.0 g/t Au at relatively low cost. The application of mineral processing technology to oil

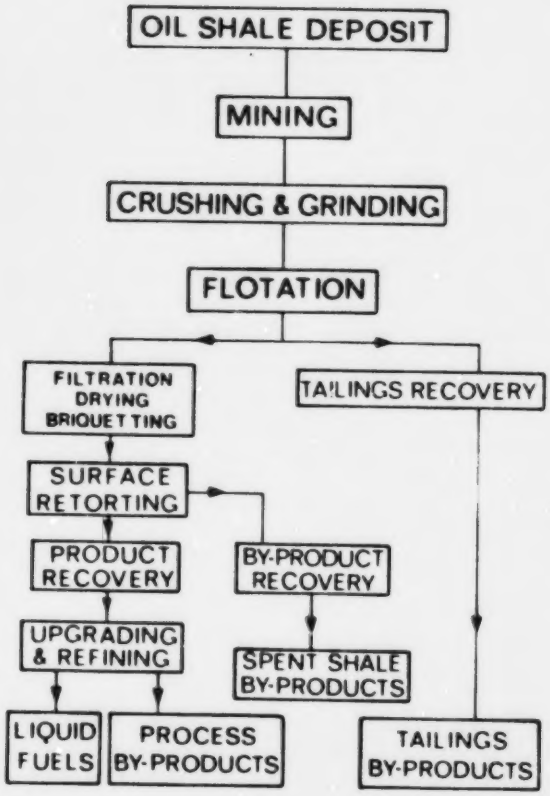

FIGURE 5-8: Beneficiation Route (source: Ward 1984).

shales has not been investigated to any great extent to the present time. Nonetheless, a reasonable degree of technical success has been achieved and additional research would most likely result in further improvements.

5.6.1.2 Rock Cobbing

By definition, a rock is a naturally formed aggregate or mass of minerals. A mineral is a naturally formed chemical element or compound having a definite range in composition. Oil shales are laminated sediments in which the constituent minerals are predominantly clay, silt and kerogen. The grain size of the kerogen and clay is finer than 20 µm, the silt is finer than 40 µm.

Crude separation of coarse-size particles without liberation of mineral matter is referred to as rock cobbing. Cobbing achieves upgrading by utilizing physical properties of the shale, such as magnetic, density and fragmentation characteristics. Capital and operating costs for this type of mineral processing are relatively low. Cobbing is most suitable for the upgrading of banded rocks and is effective on coarsely crushed or coarsely ground feed +75 µm. For banded oil shales, such as those of Colorado and Australia, cobbing using such simple techniques as screening, electrostatic and gravity separation have been shown to double the oil yields of low-grade shales. Up to 70% of the inorganic matter has been rejected, while up to 80% of the kerogen has been recovered (Ring 1981 and Parkinson 1982).

When applied to the Long Rapids shales of Ontario because of the uniform distribution of the very fine (5 µm) particles, the gravity separation techniques on coarse feed were shown to be inefficient (Watts et al. 1983). Heavy liquids gravity concentration of the -150 µm fraction grading 9.73 wt% organic carbon resulted in a concentrate equivalent to 58.4% of feed and assaying 12.74 wt% organic carbon (an increase of 31%). Some 77.6% of the carbon was recovered, based on calculated head grade, not assayed head.

The concentration results at coarse sizes (-150 µm) confirmed the work of other researchers, who are studying Eastern USA shales; i.e., that heavy media separation

works well with good recovery on banded Colorado shales, but gives poor recovery of the finely disseminated kerogen of the Eastern USA or Ontario oil shales.

5.6.1.3 Kerogen Beneficiation

The fine distribution of the kerogen in the Eastern USA and Ontario shales requires ultrafine grinding of the rock for successful physical liberation. These and other oil shales are composed of fine-grained particles (in the order of 10 µm) (Fahlstrom 1979 and Nowacki 1981).

Until the mid-1970s, fine grinding (to 100% -74 µm), followed by physical separation of finely ground ores was considered exorbitantly expensive because of high grinding energy requirements. Improvements in grinding efficiency since then have considerably reduced energy requirements and total operating costs, so that large concentrators with yearly capacities in excess of 10 million tonnes are now in operation (Klinger 1985). In one of these concentrators, hard, non-magnetic taconite ore is beneficiated, using ultrafine grinding to 30 µm to produce high-grade iron-oxide concentrates.

The separation and recovery of kerogen in concentrated form goes back to the 1920s, when kerogen concentrates were needed for physical and chemical characterization studies. Kerogen "isolation" uses wettability characteristics in two ways. The first method requires mixing of a heated water-slurry of oil shale with a kerogen solvent to give kerogen-rich pellets in a water-slurry of minerals. Separation efficiencies up to 69% have been obtained for Green River shales. The method is similar to the thermal-solution and hydrogen-donor solvent-extraction methods described in Section 6.4.7, and the advantages and disadvantages should be equivalent to thermal solution.

The second method, froth flotation, uses air bubbles to collect kerogen particles from a water-slurry of ground shale. Froth flotation requires: ultrafine grinding to liberate kerogen; the preparation of a water slurry; and the addition of air, a frother, and a collector.

TABLE 5 - 1

COMPARISON OF VARIOUS SHALES AND RESPONSES TO BENEFICIATION BY FROTH FLOTATION

Description	Green River Mahogany Zone Colorado, USA	Kvarntorp Naerke, Sweden	Chattanooga Alabama, USA	New Albany Kentucky, USA	Collingwood Ontario, Canada
Sources of Information	(1, 2)	(1, 2)	(2, 3)	(2, 3)	(2, 3, 4)
Age	Eocene	Cambrian	Devonian	Devonian	Ordovician
Origin	Lacustrine	Lacustrine	Marine Platform	Marine Platform	Marine Platform
Chemical Characteristics					
Kerogen Qualifier	Algal–Oily	Humic–Coaly	Humic	Humic	Humic
Shale Oil Qualifier	Aliphatic	Aromatic	Aliphatic–Aromatic	Aliphatic–Aromatic	Aliphatic–Aromatic
Carbonate Qualifier	Calcareous	Non-calcareous	Non-calcareous	Non-calcareous	Calcareous
Mineral Carbon (wt%)	4.4	0.12	0.79	—	6.9
Organic Carbon (wt%)	16.3	22.0	15.22	15.03	7.14
H/C Atomic Ratio	1.65	1.35	1.36	1.47	1.39
Ash Content (wt%)	65.3	72.0	79.7	77.6	65.9
Heating Value					
MJ/kg	5.86	8.37	6.63	5.64	3.49
BTU/lb	2,520	3,600	2,850	2,425	1,500
Fischer Assay					
Organic Carbon Conversion (%)	65	—	35	30	40
Oil Yield (L/t)	118.5	64.3	52.2	64.7	31.7
(US gal/ton)	28.4	15.4	12.5	15.5	7.6
(wt%)	10.9	5.9	5.6	6.9	2.9
Gas Yield (wt%)	2.5	3.6	2.9	3.6	1.8
Spent Shale (wt%)	86.8	87.7	88.7	86.0	93.7
Mineral Beneficiation					
Shale Density (g/mL)	2.2	2.2	2.5	2.2	—
Density Powder Concentrate (g/mL)	—	—	0.494	—	—
Density Briquette Concentrate (g/mL @ 138 MPa)	—	—	1.408	—	—
Cleaner Concentrate					
wt% of head	25	25	26.6	45.5	26.0
Oil content (L/t)	—	—	152.7	131.0	65.0
(US gal/ton)	—	—	36.6	31.4	15.6
Kerogen content (wt%)	56	56	—	—	—
Concentrate Yield/Head Yield	—	—	2.9	2.0	2.0
Recovery of Oil (%)	—	—	87.0	81.3	51.6
Recovery of Kerogen (%)	>90	>90	—	—	—

Sources: (1) Fahlstrom (1979)
(2) Extrapolated or inferred from various sources
(3) Hanna and Lamont (1983)
(4) OGS open file reports

Froth flotation as a beneficiation technique for oil shales was first highlighted by Fahlstrom (1979), who briefly mentioned Russian experiments while reporting on tests conducted by Boliden AB (Sweden). The Russians experimented with Estonian kukersite and obtained concentrates grading 80 wt% kerogen at 90% recovery. The Swedes beneficiated Kvarntorp (Sweden) and Green River Mahogany Zone (Colorado) shales by ultrafine grinding to 80% -15 µm and concentrated the kerogen by flotation using oil as the collector. The Swedes produced a concentrate containing 56 wt% kerogen and obtained a 90–95% kerogen recovery while rejecting 85 wt% of the inorganic matter. Fahlstrom indicated grinding energy requirements of 160–200 MJ/t (40–50 kWh/ton) for the Kvarntorp shale using conventional ball mills and 102 MJ/t (25.6 kWh/ton) in semi-autogenous mills, to achieve a flotation feed sizing of 80% -15–20 µm.

The Minerals Resources Institute (MRI) of the University of Alabama, USA, has been investigating ultrafine grinding and froth flotation on Eastern USA shales since 1981 and has also tested foreign shales and the Collingwood shale of Ontario. Hanna and Lamont (1983) produced concentrates with FA yields up to three times those of the as-received oil shales at recovery of 81.3–87% in oil shale equivalent. Rejects of non-organic material by froth flotation accounted for 50–70 wt% of the raw shale. The rejects thickened rapidly despite their extreme fineness. Clear effluent from the settled pulps had significant quantities of soluble salts.

Shale oil, kerosene, methyl–isobutyl–carbinol (MIBC), and pine oil were found to be effective collectors of kerogen, with pine oil being the most effective for kerogen recovery and froth control. Following flotation, the concentrate requires thickening and filtering to produce a concentrate filter cake containing some 50–60 wt% solids.

The cake is then dried and agglomerated or briquetted prior to retorting. Dried filter cake yielding 89 L/t (21.3 US gal/ton) has a density of 0.494, which can be increased to 1.408 under a briquetting pressure of 137,900 kPa (20,000 psig). Briquettes made at pressures of 34,400–68,900 kPa (5,000–10,000 psig) displayed good, green strength and resistance to breakage, before and after retorting (in bench-scale apparatus).

Indiana shale yielding 50.1 L/t (12 US gal/ton) was upgraded by grinding and flotation to yield a concentrate yielding 112.7 L/t (27 US gal/ton) and the concentrate was briquetted (Hanna and Lamont 1983). Hydrogen retorting of the briquettes, in laboratory-scale apparatus, yielded 225 L/t (54 US gal/ton) of concentrate. Hydrogen retorting performed on raw shale also doubled the oil yield. Thus, hydrogen retorting provides similar results on the raw shale and concentrate. Figure 5-9 shows a proposed flowsheet for Eastern USA shale prepared by MRI.

A sample of the Collingwood shale ground to 98% passing 38 µm was beneficiated by flotation, giving a cleaner concentrate representing 26 wt% of feed, yielding 65.1 L/t (15.6 US gal/ton) under FA and recovering 51.6% of the kerogen. The grade of the concentrate was 197% of the calculated head grade (Hanna and Lamont 1983). Alabama shale ground to 90% passing 10 µm gave a 26.6 wt% cleaner concentrate that yielded 152.7 L/t (36.6 US gal/ton), at a recovery of 87.0 wt%. The concentrate yield was 327% of the head grade (Hanna and Lamont 1983).

The lower yield of the Collingwood concentrate is reportedly due to the coarser grind and to the calcareous gangue that floated more readily than the siliceous gangue of the Alabama shale (Hanna and Lamont 1983). Sulphur reported to the concentrate, some of it may be in the form of pyrite. On Alabama and Kentucky shale, recoveries of oil and organic carbon were high, at 81.3% and 87.0% indicating that little energy value was left in the tails. The Alabama cleaner concentrate was enriched in vanadium (345 ppm), molybdenum (400 ppm) and uranium (45 ppm), from the levels of 126, 168 and 20.4 ppm, respectively, in the calculated feed. The levels of cobalt, chrome, nickel, titanium, and silver in the Alabama cleaner concentrate were similar to those in the feed.

A limited amount of grinding and froth flotation test work was also performed on samples of the Long Rapids Formation (Watts et al. 1983). The results were encouraging but inconclusive.

Misra et al. (1983 and 1984) reported on liberation and flotation parameters affecting kerogen concentration. In 1983, they tested the energy requirement of three various mills to achieve a product whose particle size was 80% finer than 20 µm from a minus

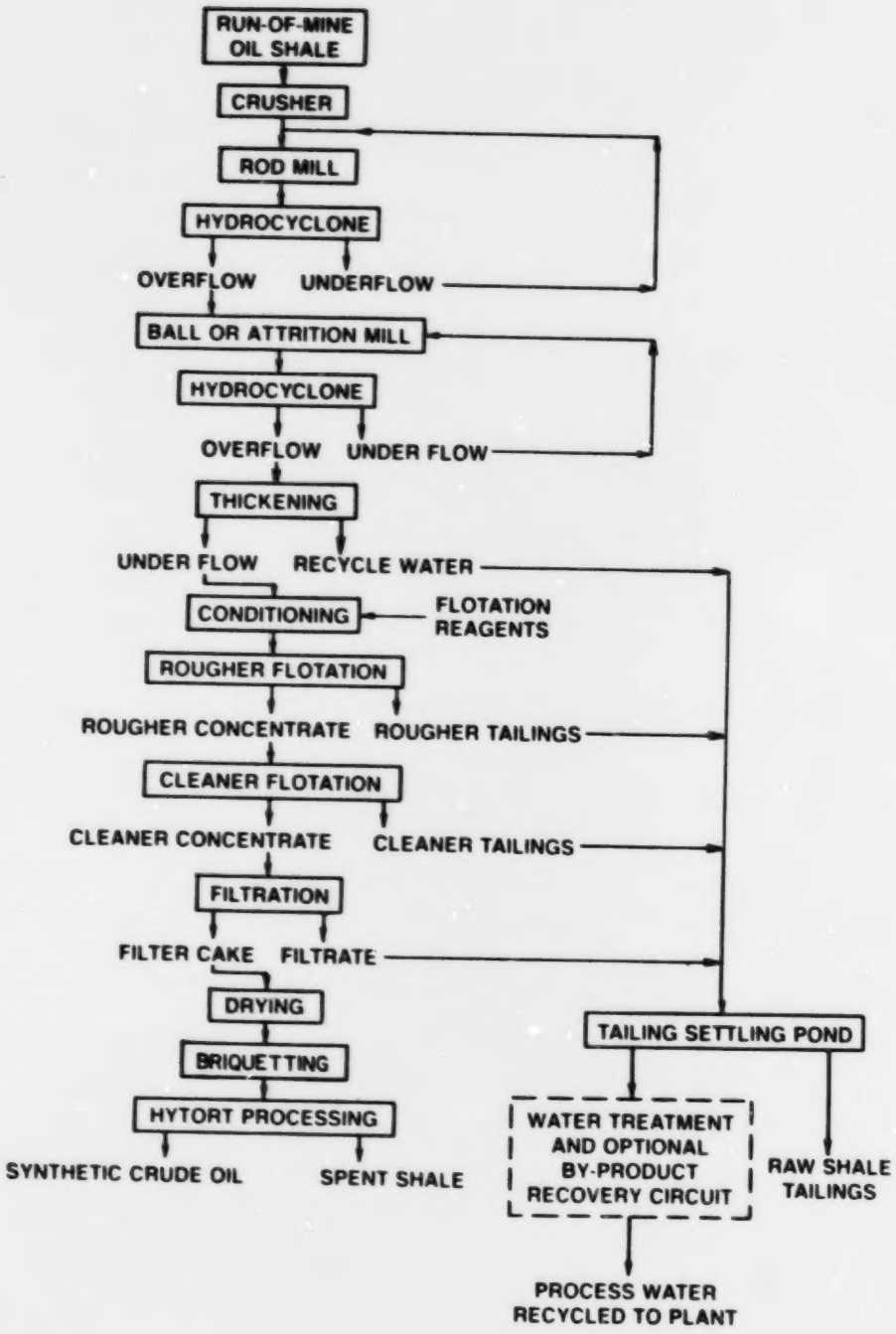

FIGURE 5-9: Schematic flowsheet for MRI oil shale beneficiation plant (source: Tippen et al. 1984).

2.3 particle size feed. The requirements were: 211 MJ/t (53 kWh/ton) for a conventional ball mill, 139 MJ/t (35 kWh/ton) for an attrition mill, and 104 MJ/t (26 kWh/ton) for a high-speed stirred ball mill. In 1984, they found that, at ambient temperature, critical size for maximum kerogen liberation is about the 18–13 µm range and that under thermal grinding, the critical size is increased to 28–18 µm range. The coarser liberation size range is believed to be related to the coalescence of kerogen particles, and the reduced bonding between the kerogen and the inert mineral matter. The addition of 2.7 L/t (0.7 US gal/ton) of diesel fuel during grinding further enhanced liberation. From mining industry experience, it is assumed that most of this fuel should report to the kerogen concentrate.

Material ground at high temperature had a higher flotation rate, required less frother, and showed an improved grade/recovery curve compared to ambient-temperature ground material. Kerogen recovery increased with flotation temperature to a maximum of 40°C, where it started to decrease. Flotation produced a rougher concentrate that had to be retreated in two or more stages to obtain a final cleaned concentrate assaying in excess of 50 wt% kerogen. Laboratory experiments have shown that ultrasonic treatment of the rougher concentrate may reduce the number of flotation cleaning stages, from three to two to obtain a concentrate assaying 50 wt% kerogen. However, kerogen recovery was lower.

Protopapas et al. (1984) tried to quantify the relative merits and demerits of froth flotation for Western USA oil shales. They showed that:

1. For an operating mine-retort complex, the installed capital cost, in 1983 dollars, of a froth–flotation circuit capable of treating 8,000 ton/d should be US $13.5 million. The circuit included tertiary pebble mill, hydroseparator, flotation cells, cleaning cells, thickener, filter, and miscellaneous equipment.
2. The power requirement using a pebble mill was estimated at 160–200 MJ/t (40–50 kWh/ton) to achieve a feed finer than 20 µm.
3. In conventional retorting, solids handling such as mining, crushing, conveying, disposal, etc. comprises 29.4–35.4% of the total capital cost. The costs of the retorting component range from 15% to 29.9% of the total.
4. About 65% of the selling price of oil is related to capital costs and 35% operating costs; and of the operating costs, 36% are related to mine and material handling and only 23% are related to retorting.

Protopapas et al. (1984) concluded that increased solids handling costs can mask any benefit derived from decreased retorting costs and that capital costs related to beneficiation should not exceed the average 23% of the total capital cost of retorting as-mined shale. This applies especially to the retorts with relatively lower capital and operating costs, such as the Paraho CH retort or fluidized bed retort. Likewise, to be effective, additional operating costs related to beneficiation should be much lower than 8% of the required selling price of a retorting plant without beneficiation (or 35% total operating x 23% for the retorting portion).

According to Protopapas et al. (1984), beneficiation of a 66.8 L/t (16 US gal/ton) Colorado shale to 125 L/t (30 US gal/ton) would decrease total capital cost by 32.5%, but would add US $10/bbl to the selling price of the shale oil produced. This represents an increase in total operating costs of US $3.81/ton of raw shale.

WGM has reviewed the Protopapas study in terms of Eastern USA and Ontario oil shales. In our opinion, the estimated capital cost of the froth-flotation circuit mentioned is too low and would more likely approximate US $50 million. Concentrate drying and agglomeration/thickening units may have been omitted from this estimate.

While the energy required for grinding is high, at 200 MJ/t (50 kWh/ton), this would most likely be reduced by the use of a semi-autogeneous or high-speed stirred ball mill. Furthermore, this requirement may represent only 10–15% of the total energy inputs required for mining and processing, and, in our opinion, would not have a detrimental impact on the overall energy ratio (Section 8.4).

Mining of Colorado shales will be by underground room-and-pillar methods and, therefore, the mining and materials handling portion of operating costs can be expected to be higher than those for the Eastern USA and Ontario oil shales, which will most likely be mined by open-cast methods. In our estimation, both capital and operating costs associated with retorting Ontario oil shales will be considerably higher than those associated with mining, materials handling and disposal.

5.6.2 ANALYSIS

5.6.2.1 Considerations for Ontario Oil Shales

Mineral beneficiation is used by the mining industry because it is particularly effective in reducing processing costs of mineral deposits. In cases such as low-grade porphyry copper and placer gold deposits, separation of the gangue from valuable minerals can reduce the size of a processing plant by reducing volume and tonnage of throughput by factors of 10 to more than 100. This brings enormous savings in capital and operating costs.

One obvious benefit of preconcentration of kerogen is that all of the mined shale is utilized. For conventional retorting in many processes the feed must be crushed and screened. This step can result in losses of up to 20% of the mined shale as fines. A kerogen concentrate with a recovery of more than 80% could therefore represent a gain in oil recovery rather than a loss.

However, in the case of an oil shale industry, the commodity (kerogen) is lighter than the gangue and represents a high proportion (in excess of 12 vol%) of the mined material. Although oil shale retorting is heat intensive, beneficiation of Ontario shales via ultrafine grinding and froth flotation may or may not bring capital and operating cost savings as explained below.

Beneficiation would require large amounts of energy, especially for grinding to -20 μm, and for drying and briquetting of concentrates; however, it is not anticipated that these additional energy requirements would result in a negative energy ratio.

Preparation of kerogen concentrate would mean that a lighter mass would be fed to a retort, but not necessarily a smaller volume. A good-grade oil shale would contain 10–20 wt% kerogen, but because of the low density of kerogen, the 10–20 wt% range represents between 20–40 vol% of the in-situ rock. Crushing and grinding would further increase the volume by some 30%.

In principle, beneficiation of an Ontario shale containing 10 wt% kerogen, to a dried kerogen-only concentrate should, on a weight basis, bring the required retort size to less than 10% of the feed (by rejecting all 90% of the inorganic matter in the feed plus some kerogen that would be lost). However, because of the low density of kerogen and the increase in volume related to added porosity created by grinding, it is unlikely that, on a volume basis, such a pure concentrate would represent less than one-third of the as-mined feed. A concentrate consisting of pure kerogen could have a volume of up to 29% of the mined shale (or 10 wt% x 2.3 ÷ 0.8). This assumes that the mined feed has a density of 2.3, and that briquettes are prepared of pure kerogen with a 20% porosity and a density of about 0.8. Furthermore, heating to retorting temperature of high oil yield feeds could increase the volume of the concentrate by 20%. Such increase has been reported on rich Colorado and kukersite shales. Hanna and Lamont (1983) demonstrated that a briquetted concentrate containing about 30 wt% kerogen has a density of 1.408 and represents about 27 wt% of the feed, giving a volume of nearly 48% of the as-mined shale.

Thus, the size of the retort could be reduced by up to 40%, depending on concentrate and retort characteristics. Retoring parameters for a kerogen concentrate from Ontario oil shales will have to be established by test work before the overall benefits can be determined.

Results of the test work completed at MRI in Alabama have shown that valuable trace elements (vanadium, molybdenum and uranium) concentrate with the kerogen. The recovery potential for these metals is thus considerably enhanced. Additional revenues accruing to an oil shale operation from metals recovery could partially offset the costs of the beneficiation step.

From the preceding considerations, a series of advantages and disadvantages can be inferred.

The advantages of the beneficiation route may be:

(1) opportunities to economically treat lower grade oil shales and to increase the resource;

(2) opportunities for better overall recovery of the latent energy of the kerogen, from the mined shale;

(3) potential for reduction in size or number of retorts resulting in reduction of capital and/or operating costs;

(4) physical and chemical uniformity of the beneficiated feed, and improved kinetics, and greater chemical reactivity of the feed during retorting;

(5) opportunities for significant improvement in overall process-energy efficiency, greater process flexibility, and overall operating control in the treatment of the kerogen;

(6) enhanced metal recovery potential for those trace elements which concentrate with kerogen; and

(7) the opportunity to combine, mix and transport concentrates from several mines by pipeline to a retorting and refining plant that may be sited close to an energy centre (nuclear power station) or to an oil refinery.

The main disadvantages may be:

1. If recovery of kerogen is less than the loss of fines due to particle sizing, then for a fixed daily production of oil in an equivalent process, kerogen losses to tailings could mean mining and handling higher tonnages of raw shale and waste.

2. Depending on the grade of the concentrate, the low density of a dried filter cake of beneficiated feed may have a volume equal to or greater than the run-of-mine shale. Briquetting the beneficiated feed may compensate for the lower specific gravity to produce a volume similar to or less than run-of-mine material.

3. Loose or powder-dried concentrate would be too fine for most retorts and an agglomeration/briquetting step would have to be incorporated.

4. End-products of a fluidized bed retort accepting ultrafine powder could be penalized or rejected by refineries if they contain excessive amounts of particulates.

5. Most retorting processes are geared to a particular range of grades in the feed and some do not accommodate high-grade feeds. For all non-fluidized bed processes, high-grade feeds are known to give agglomeration and/or bridging problems.

6. The energy required for the grinding step has been reported to be quite high. However, this could most likely be reduced by the use of semi-autogeneous or high-speed stirred ball mills.

7. The very fine-grained waste may occupy a much larger volume than shale, which has only been crushed, and may necessitate additional disposal costs.

Concentration of the kerogen to obtain upgraded retort feed involves some definite unknowns that have yet to be addressed and that are related to ultrafine grinding and high-grade retort feed. These unknowns include: 1) total capital costs of plant equipment; 2) beneficiation and retorting operating costs; 3) total energy requirements; 4) retorting parameters of the concentrate; and 5) environmental impact.

5.6.2.2 Conclusions

Concentration tests have shown encouraging results in preparing concentrates yielding in excess of 152.7 L/t (36.6 US gal/ton) under FA from fresh Eastern USA shales yielding 52.2 L/t (12.5 US gal/ton). Potential benefits that could be achieved include improved process–energy efficiency, optimization of oil yields, recovery of valuable metal byproducts, and a reduction in capital and/or operating costs.

Retorting preceded by fine grinding and froth flotation does, however, involve a number of unknowns. The most important ones are energy requirements, the total capital and operating costs, and reaction of the concentrates in a commercial-scale retort.

The disadvantages and potential problems listed earlier must be answered and weighed against the potential advantages listed. At this stage in the evaluation of process routes, the unknowns associated with beneficiation of oil shale prevent a fair assessment of the beneficiation route, in terms of energy savings and capital and operating cost savings over direct or conventional retorting.

In our opinion, the resolution of these problems can only be achieved by a carefully planned program of test work and evaluation that would:

- develop a flowsheet for concentration of kerogen from Ontario oil shales;
- determine the retorting parameters of the concentrate;
- select or re-design a retorting process to handle the concentrate;
- establish the technical feasibility for recovery of byproducts from the retorted concentrate; and
- compare the technical and economic benefits of the beneficiation route to those of the conventional route for Ontario oil shales.

5.7 COMBUSTION ROUTE

5.7.1 DESCRIPTION

Direct combustion of oil shales is practiced in Soviet Union, China and Germany, where the organic matter of the shales is burned to produce steam for power generation (Figure 5-10).

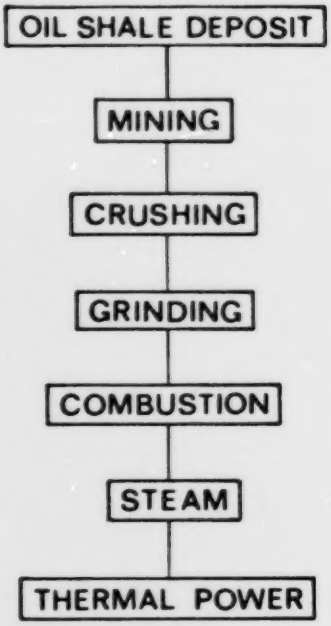

FIGURE 5-10: Combustion Route.

In Estonia (USSR), the burning of some 23 million tonnes per year of kukersite (a rich oil shale) produces the steam that operates two 1,600 MW generators. Kukersite occurs in seams less than 3 m thick: it is calcareous, has a combustion heat that varies from 9,000 to 13,000 MJ/t (3,870 to 5,590 BTU/lb), and can be made to yield between 16–23% oil under retorting. The shale is burned in pulverized form, and flue gases are cleaned with two-stage cyclones and Cotrell precipitators to reduce particulate contents to 0.3–0.4 g/m^3.

Ashes are completely oxidized and contain interesting amounts of uranium, molybdenum, nickel, rare earths, etc., for which recovery is being investigated. Ashes are also rich in clinker-forming ingredients, valuable as binders, and do not contain water-soluble sulphides. Combustion is conducted at high temperature and any potential carcinogenics, polycyclic hydrocarbons, phenols or other poisonous organic compounds are eliminated. Ashes are also used in agriculture to reduce soil acidity, and in the cement industry (Mining Magazine 1985).

In China, oil shales from Maoming, Kwangtung Province have been burned in fluidized bed combustion/heating (**FBC**) boilers for power generation since 1965.

New oil-shale burning plants utilize FBC boiler versus the stoker-fired or pulverized-fired boiler. Properly designed FBC reactors can handle fuels in various physical states and are highly adaptable to fuel variations. Such boilers, primarily developed for the combustion of high-sulphur coals and for fuels with low heating value, such as coal tailings, have been modified to accept gaseous, liquid or solid fuels, or a combination of these. Such adaptability is related to the state of fluidization and to the presence of a thermal adsorbent inside FBC reactors.

FBC reactors have many advantages:

(1) high heat load per unit distributor area;

(2) burning of a wide variety of fuels that can have ash contents as high as 70%, or heating values lower than 4,000–5,000 MJ/t (1,720–2,150 BTU/lb), or water content as high as 60%;

(3) insensitivity to volatile matter content and caking;

(4) low operating temperatures that are less likely to alter the chemical and physical characteristics of minerals;

(5) no necessity to remove NOx because of the low temperature of combustion and no removal of sulphur dioxide, if the fuel is calcareous or if limestone is added; and

(6) capital costs of FBC that are competitive with conventional solid fuels burners.

The disadvantages of FBC are:

(1) high elutriation rates;
(2) high particulate emissions;
(3) high pressure head to maintain fluidization; and
(4) high erosion rates to the components of the reactor or of the boiler.

In the Western Hemisphere and more particularly in English-speaking industrialized countries, there exist extensive reserves and resources of coals and lignites; therefore, only limited research has been devoted to direct combustion of low-heating-value, high-ash-content fuels, such as oil shales. Only a few research papers have been located in the English literature. One of them (Pitrolo and Shang 1980) summarized tests conducted at the Morgantown Energy Technology Center, Morgantown, West Virginia, where calcareous oil shales from Colorado, Israel and Morocco were burned in FBC reactors.

The tests indicated that all three shales could easily be processed in FBC reactors and that high combustion efficiency could be achieved. The Moroccan shale was the only one with some of the limestone not being calcined, even at longer residence time and temperature than normally applied to FBC reactors. Secondary air injection was needed to burn all combustibles in the freeboard, where the temperature remained too low. At temperatures below 760°C, carbon-monoxide emissions were not reduced, even with secondary air injection. Nitrogen-oxide emissions exceeded USA standards. Ash-fusion temperature was 1,480°C for Israeli shale and 1,200°C for the Colorado and Morocco shales. Excessive size reduction appeared to release trapped volatile hydrocarbons. Solid handling problems were forecasted, in the event that a combination of excessive fines and moisture are encountered in the fuel feed. There appeared to be an optimum shale-size feed for optimum efficiency. For calcareous shales, the authors indicated that bed temperature should be controlled to prevent calcination, an undesireable endothermic reaction (Pitrolo and Shang 1980).

Combustion tests in reducing and oxidizing atmosphere were conducted on spent shale from two units of Kentucky shales (Robl 1980). The tests indicated that the shales are refractory, with a 1,240°C temperature being recorded for initial ash deformation.

Reducing atmosphere fusion tests showed initial deformation temperature mainly at 1,260°C, softening temperature at 1,300°C, hemispherical temperature at 1,365°C, and fluid temperature between 1,455°C and 1,495°C. Oxidizing atmosphere fusion showed initial deformation between 1,305°C and 1,370°C, softening between 1,375°C and 1,410°C, hemispherical at 1,450°C, and fluid temperature from 1,495°C to more than 1,510°C. Swelling of the samples was observed in the oxidizing atmosphere.

Chemical analyses performed on the four foreign shales and their ashes are shown in Table 5-2. Also included are analytical results from shales of the Albert Formation of New Brunswick, and hypothetical results for the Long Rapids, Kettle Point and Collingwood of Ontario. The Ontario shales were not tested for combustion; therefore, for comparative purposes, we have calculated and/or extrapolated a series of data using information from multiple sources. An effort has been made to indicate how representative geological occurrences of these shales would react under combustion testing. The results shown for the Ontario shales must be considered with caution.

Table 5-2 shows large variations in the chemical analyses of the eight units and that:

1. The shales of Israel, Morocco, Colorado, New Brunswick, and Collingwood are calcareous, the last four units being dolomitic.
2. The Long Rapids and Collingwood have much lower organic carbon contents than the foreign shales, and the Kettle Point and New Brunswick shales have intermediate organic carbon contents.
3. The shales from Israel, Morocco, Kentucky, and the Long Rapids and Kettle Point shales have high sulphur content; the Collingwood has an intermediate content; and those of New Brunswick and Colorado have low sulphur content.
4. The nitrogen content of the Colorado shale is about twice as high as of the other shales.
5. The hydrogen content of the Ontario and Kentucky shales is much lower than the others and, at equal organic carbon, they have low oil and gas yields under FA. These shales show low organic carbon conversion under inert atmosphere retorting.
6. The shales have high ash contents and low to moderate moisture contents.
7. The Collingwood is relatively low in silica and has moderate calcium oxide content. The shale has potential as clinker for the cement

TABLE 3-2

CHEMICAL ANALYSIS OF SOME OIL SHALES UNDER CONSIDERATION FOR COMBUSTION

Description	Israeli Shale	Morocco Shale	Colorado Shale	Kentucky Sunbury Shale	New Brunswick Shale	Long Rapids Shale	Kettle Point Shale	Colling-wood Shale
Information Sources	(1)	(2)	(3)	(4)	(5)	(6)	(6)	(6)
Mineral Carbon (wt%)	6.27	4.33	4.42	0.48	2.67	0.30	0.4	6.5
Total Organic Carbon (wt%)	8.59	11.87	12.74	11.48	10.68	7.27	10.0	7.5
Ultimate Analysis (wt%)								
Moisture	5.14	5.78	0.64	1.66	0.56	2.00	3.1	1.3
Ash	56.61	62.16	68.00	81.63	79.36	82.60	78.3	65.9
Sulphur	2.15	2.28	0.65	3.67	0.70	2.67	2.8	1.2
Hydrogen	1.52	1.62	2.48	1.28	1.67	1.02	1.3	0.9
Nitrogen	0.42	0.37	0.74	0.42	0.20	0.33	0.4	0.3
Carbon Total	14.86	16.20	17.16	11.88	13.34	7.57	10.4	14.0
Oxygen (by diff.)	19.30	11.61	10.32	—	3.73	3.81	3.7	16.4
Ash Analysis (wt%)								
SiO_2	22.78	39.78	48.52	66.08	60.76	63.84	63.58	36.19
Al_2O_3	10.36	11.28	11.62	16.02	16.38	14.16	15.33	10.68
Fe_2O_3	3.91	5.18	5.10	8.57	6.16	5.74	7.26	4.61
CaO	50.62	29.18	18.10	.26	7.94	3.96	2.28	33.21
MgO	0.36	5.26	7.63	1.48	3.52	2.96	2.45	5.90
Na_2O	1.19	0.59	3.49	.37	3.00	0.14	0.69	ND
K_2O	0.72	1.55	2.73	4.21	2.25	3.78	3.60	4.96
P_2O_5	2.86	2.77	0.38	—	—	0.01	0.10	0.84
TiO_2	0.41	0.54	0.45	0.73	—	0.79	0.88	0.53
SO_3	6.08	5.20	2.68	—	—	4.40	4.18	3.08
Sub-total	99.92	101.33	100.70	97.72	100.01	99.78	100.35	100.00
High Heating Value (MJ/t)	4,450	5,920	6,620	5,000(6)	4,310(4)	3,260	4,420	3,720
Information Sources	(6)	(6)	(6)	(4)	(6)	(6)	(6)	(6)
Oil Yield (US gal/ton)	12.5	18.0	27.8	10.8	21.9	7.7	10.4	9.7

Sources:
(1) Pitrolo and Shang (1980); sample CH 2486
(2) Pitrolo and Shang (1980); average of CH 2483 and CH 2492
(3) Pitrolo and Shang (1980); average of CH 2501 and CH 2505
(4) Robl et al. (1980); Sunbury, hole Kep N°. 6
(5) Barua et al. (1984); average of shales 1 and 2
(6) Calculated and extrapolated average from various public sources

industry; however, the cumulative contents in magnesium, potassium, phosphoric, and sulphuric oxides may be detrimental.

8. The inferred higher heating value for the Ontario shales should, at equal organic carbon and sulphur contents, be equivalent to that of the other shales.

5.7.2 ANALYSIS

The limited data available indicate that the Ontario shales could technically be burned in a FBC boiler for the production of steam in electric power generation. However, Ontario Hydro is the only authority in the Province to produce electricity and it does not use FBC for electric power generation.

A letter was sent to the Power Equipment Department of Ontario Hydro Corporation to enquire about possible utilization of the shales as primary or secondary indigenous fuels. The letter showed data similar to those of the Kettle Point and Collingwood presented in Table 5-2.

The public utility replied that it has conventional pulverized coal boilers and the as-described shales are not acceptable as primary or secondary fuels, as they would create operating and maintenance problems. The Corporation also feels that the shales are too low in heating value to be very effective in FBC.

Unless Ontario Hydro developed FBC boilers for power generation or unless better quality shales can be found, our study indicates that combustion is an unlikely route for the shales of Ontario. They have low heating value and high ash content and, in the long-term, they would be poor competitors to natural gas, coal or uranium, which have high heating values and are readily available in Canada.

5.8 CO-COMBUSTION ROUTE

5.8.1 DESCRIPTION

The New Brunswick Albert shale and the Colorado shale in Western USA are calcareous, and they have been tested for combustion-chamber absorption of sulphur dioxide during combustion of high-sulphur coals in stoker-fired or pulverized-fired boilers. Furthermore, New Brunswick is currently investigating the integration of fluidized-bed co-combustion of high-sulphur coal with calcareous raw shale fines and spent shale and indirect retorting of raw oil shale (Figure 5-11).

Fixing sulphur dioxide with the use of limestones or calcareous oil shales is not new. As mentioned in Section 5.7.1, Pitrolo and Shang (1980) experimented with FBC on calcareous and/or dolomitic shales from Israel, Morocco and Colorado.

In the same period, Doyle (1980) reported on sulphur retention, by using Colorado oil shale as the fixing medium in the fluidized-bed combustion of high-sulphur coal at bed temperature of 800°C. Doyle's experiments indicated that combustion of a coal containing 3.5% S could meet USA standards in sulphur retention (less than 90%), if calcareous oil shale is added to a CaO : S molar ratio of about 2.5 : 1. The standards could also be met with limestone addition, but a CaO : S molar ratio of 4.0 : 1 would be required for a limestone containing 93% $CaCO_3$ (or 15% CaO). Burning one tonne of coal containing 3.5% S would require one tonne of 15% CaO shale or about 0.5 tonne of 52% CaO limestone. The lower molar ratio requirement for the shale is related, according to Doyle, to the higher porosity, the finer granulometry, and the presence of a natural catalytic component of the Colorado oil shale versus limestone.

The latent energy in calcareous oil shales is an added advantage in sulphur removal, but the much higher ash content becomes an operating disadvantage in conventional boilers that can not tolerate high ash contents.

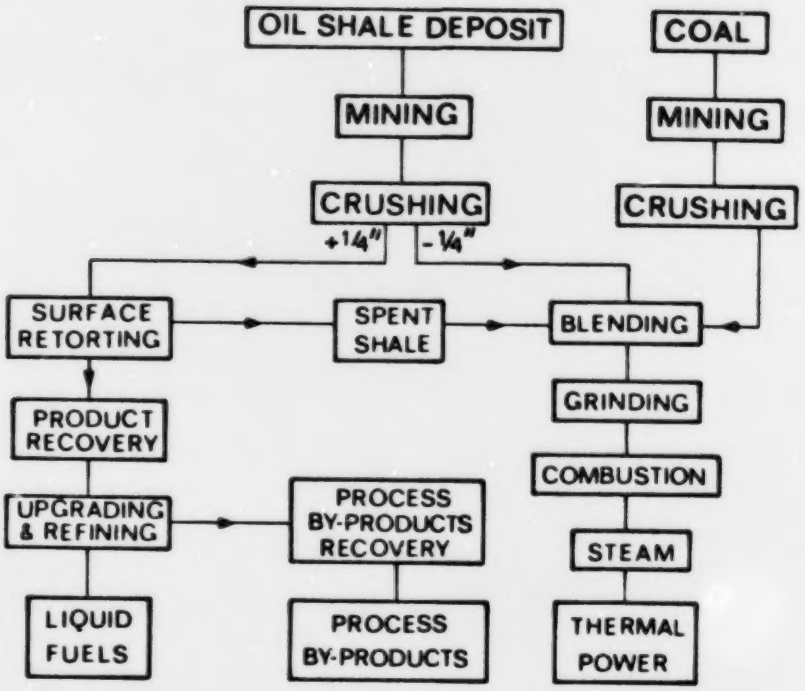

FIGURE 5-11: Co-Combustion Route (source: Ward 1984).

According to Pitrolo and Shang (1980), sulphur-oxide retention by calcareous material requires calcining to form fresh lime, which reacts with sulphur dioxide in the presence of oxygen to form calcium sulphate. The simplified reactions are:

$$CaCO_3 \longrightarrow CaO + CO_2$$
$$CaO + SO_2 + \tfrac{1}{2} O_2 \longrightarrow CaSO_4$$

The combined reactions are endothermic, thus the apparent advantage of the heating value of calcareous oil shale versus limestone free of organic matter. Most oil shales, containing in excess of 10% organic carbon, have a calorific value greater than 4,190 MJ/t (1,800 BTU/lb).

The Research and Productivity Council (RPC) of New Brunswick experimented with the calcareous oil shale of the Albert mine as a replacement for limestone as a medium for reducing sulphur dioxide emission from high-sulphur coal combustion in conventional boilers utilizing pulverized coal or in fluidized-bed combustor/boiler.

Rotary-furnace trials at RPC indicated effective retention, with calcination of less than 80% of the carbonate when combustion was maintained below 800°C at 30 to 180 minutes retention time (Gilders and Salter 1982). The trials showed that combustion of Albert shale in the presence of sulphur dioxide gases gave effective retention and produced excess heat over that required to maintain the reactor temperature at 800°C. Cooling water was necessary. The experiments also indicated that co-combustion of one part Minto coal containing 7% S with three parts of Albert shale yielding 125 L/t (30 US gal/ton) oil should give sulphur dioxide retention in excess of 90%.

RPC (1982) experimented with FBC at spatial gas velocities below 160 cm/sec on oil shale feeds having a size finer than 0.6 cm. Retention in sulphur dioxide of up to 93% was achieved with a coal-to-shale mix having a ratio of 1 : 3.11. Sulphur dioxide retention was less than half, at a 1 : 1.83 ratio of coal to shale. Experiments in conventional coal-fired plants also indicated that Albert oil shale could replace limestone as a medium for sulphur dioxide retention in combustion.

An economic evaluation indicated that retrofitting the Dalhousie N°. 2 conventional coal-burning power station to accept washed Minto coal would bring the total operating cost to 44 mills/kWh and that adding conventional limestone scrubbers would increase the cost to 57 mills/kWh. The evaluation showed that oil shale scrubbers would increase the cost to only 52 mills/kWh.

5.8.2 ANALYSIS

The utilization of Ontario shales as co-combustibles would be for steam production in electric power plants and Ontario Hydro Corporation has virtual exclusivity. The Corporation has conventional pulverized coal-fired boilers and the low heating value, high-ash content and abrasiveness of the shales compared to coal would create substantial operating and maintenance problems in co-mixing oil shale and coal.

The use of calcareous oil shales for sulphur dioxide reduction has been proposed by various research groups. However, the aforementioned disadvantages appear to outweigh the heating value advantage, and good quality limestones still appear to be preferable for use in sulphur removal.

Like the combustion route, unless Ontario Hydro developed FBC boilers for power generation or unless better quality shales are found, co-combustion has no potential. In view of Canada's abundant resources in natural gas, coal and uranium, the low-heating-value shales are poor competitors for steam generation, or even for heating.

5.9 CONCLUSIONS

The oil shales of Ontario contain a vast resource of latent energy that is stored as kerogen, a complex organic compound (or biopolymer) that can generate heat under combustion or be transformed into liquid or gaseous synfuels by retorting.

This chapter has identified six routes to recover the latent energy of oil shales. They are:

(1) true in-situ retorting;
(2) modified in-situ retorting;
(3) conventional surface retorting;
(4) oil shale beneficiation followed by surface retorting;
(5) combustion; and
(6) co-combustion.

The shales have low heating values and, as combustibles, make poor competitors to natural gas, coal and lignite, for which Canada has abundant long-term resources. The combustion and co-combustion routes are therefore unlikely routes for the utilization of Ontario shales.

Canada's long-term supplies of natural crude are uncertain, and the production of synthetic crude oils for distillation into liquid transportation and heating fuels should take priority over combustion for heat generation. Synthetic crude oils may also be used as feedstocks for the petrochemical industry.

Synthetic crude oils from shales could be obtained by the upgrading and hydrogenation of raw shale oil, which is one of the products generated by pyrolysis of the kerogen contained in the oil shale.

Some of the sedimentary formations in Ontario have units that contain significant amounts of organic matter represented by total organic carbon contents ranging from less than 5% to more than 12% over mineable thickness. These units can be made to yield from 20 to 65 L/t (4.8–15.6 US gal/ton) oil and from 2.0% to 4.0% gas under normal conditions of pyrolysis or FA. Under these conditions, some 15% to 50% of the organic carbon is converted to liquid and gaseous hydrocarbons and 50% to 85% is left in spent shale as residual carbon or coke. The oil to gas wt% ratio varies from a low of 0.6 : 1 to a high of 14.7 : 1.

With hydrogen retorting, as developed by HYCRUDE Corporation, the oil and gas yields of Ontario shales can be more than doubled by increasing organic carbon conversion. Retorting parameters can be adjusted to produce varying ratios of oil to gas.

Retorting is carried out in a confined space, either a man-made vessel in a surface plant or a man-made enclosed volume underground. To be effective, however, retorting must be conducted under closely controlled parameters. These parameters include type, quality and quantity of kerogen being retorted, and of the inert matter encapsuling that kerogen; as well as porosity and permeability, temperature, heating rate, pressure, sweep-gas velocity, etc.

Retorting in a surface plant is capital intensive and has high operating costs. To reduce these costs, true in-situ retorting and modified in-situ retorting have been proposed. Both methods require creation of artificial permeability within the rock mass to permit gas sweep and oil recovery. The permeability is induced through explosive fracturing via boreholes (for in-situ) or mined openings (modified in-situ) to create voids. Uniform permeability is extremely difficult, if not impossible, to achieve through artificial means; and oil yields are usually in the range of 30% to 60% of laboratory FA yields in large-scale true or modified in-situ underground experiments. The shales of Ontario provide low organic-carbon conversion and low oil yields under laboratory FA; and much of the latent energy of the shale would be left behind in a spent shale that could be chemically reactive. Underground retorting in the presence of reactive hydrogen would be exorbitantly costly in such a poorly controlled environment. Because of low energy recovery and environmental hazards, true and modified in-situ routes are unlikely options for Ontario.

Retorting in surface vessels (conventional route) is capital intensive with high operating costs. The conventional route requires mining and haulage of oil shale, feed sizing, retorting, hydrocarbons recovery and upgrading, mineral byproducts recovery, and disposal of spent shale.

Mineral benefication is used by the mining industry to reduce processing capital and operating costs. Beneficiation is particularly effective in reducing processing costs of low-grade mineral deposits. In such cases, reduction in volume and tonnage of plant throughput by factors of 10 to more than 100 times have been achieved.

A review of the results of kerogen concentration test work of Eastern USA oil shales has indicated that it is technically feasible to prepare kerogen concentrates from

Ontario oil shales. However, many questions remain, such as how simple or how difficult it will be to retort these or even higher grade concentrates. Other unknowns are the energy requirements and the capital and operating costs of a commercial-scale kerogen concentrating plant.

Were there an urgent need to develop Ontario oil shales immediately, then we would have to conclude that the conventional route offers the best technical option for development at this time. However, we believe that the potential improvements in technology development offered by the beneficiation route require further investigation by a planned program of test work and evaluation before a final decision can be made.

6. SURFACE RETORTING

6.1 GENERAL

In the previous chapter on the processing technology, six routes for recovery of energy from oil shales were reviewed. In five of these routes, shales are retorted to obtain oil and gas, and in three of them, mined shale must be transported to surface retorts for processing.

Surface retorting is conducted within the confines of a vessel in which heat is applied to the shale to effect thermal decomposition of the kerogen. Retort loading and unloading can be by batch (fixed-bed) or continuous (moving-bed) operation. Moving-bed systems tend to be more efficient, because of reduced capital and operating costs and a steady, continuous flow of products of more uniform quality.

There are hundreds of patented retorts in various stages of development and these have been variously classified. The simplest classification is that of Guthrie (1964), in which retorts are grouped into four major types based on application of retorting heat (Figure 6-1). In Type I retorts, heat is applied through the walls of the retort. Type II retorts are heated by a combustion zone maintained within the confines of the retort. In Type III retorts, hot gases or liquids are circulated within the shale bed. As for Type IV retorts, the fresh cold shale is blended with super-hot solids. In this chapter, we will review 18 of the best known retorting processes. These are:

Type I:	Fischer, Pumpherston;
Type II:	Circular-Grate, Near-Surface (NSR), Flash Hydropyrolysis;
Type III:	Union 'B', Paraho CH, Petrosix, fluidized bed, HYTORT, and thermal solution and hydrogen-donor solvents; and
Type IV:	Tosco HSP, Lurgi-Ruhrgas, SPHER, Battelle MSFB, PEDCo, Taciuk.

The Fischer retort is a laboratory apparatus that is used in the early stages of the investigation of potential oil shales. The Pumpherston retort was developed in Scotland and used widely at the end of the 19th century and at the beginning of the

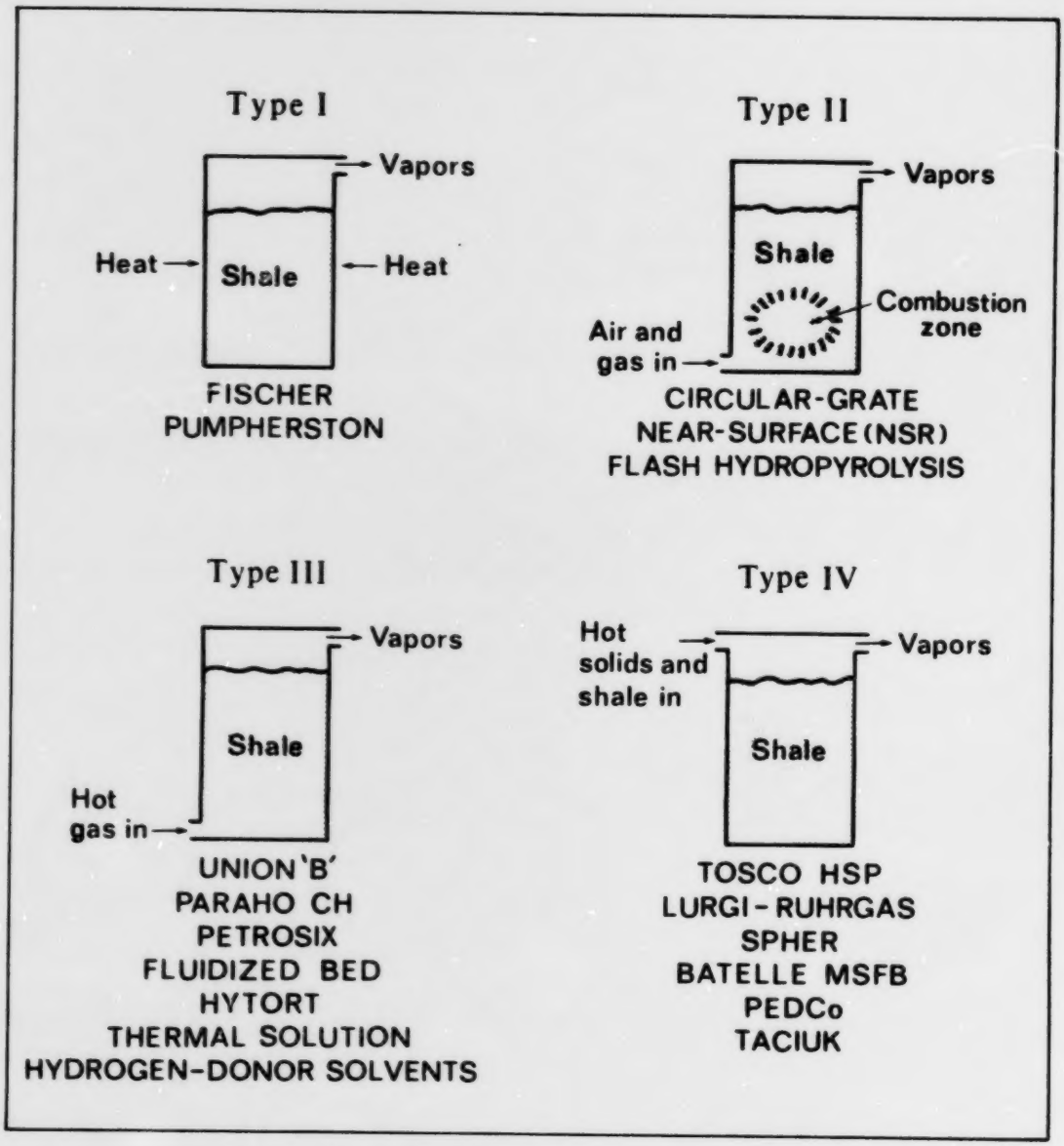

FIGURE 6-1: Retort types (adapted from Guthrie 1964).

20th. It is the only one from the above list that reached commercial operation, due to the relatively high prices of hydrocarbons at that time.

The Union Type 'B' and the Petrosix retorts have reached industrial modular scale and should be in commercial operation in the near future. They were respectively developed for high-yielding (160 L/t or 38 US gal/ton) Green River shale of the USA and the moderately yielding (80 L/t or 19 US gal/ton) Irati shale of Brazil.

The other 14 retorts are in various stages of development ranging from conceptual, through laboratory-scale testing, to pilot plants of small- to large-scale.

Time and budget restraints prevented the gathering of sufficient information on the operating Soviet Union's Kiviter and Chinese retorting processes, and on the Moroccan T3 process, which uses steam during retorting.

Strictly speaking, thermal solution and hydrogen-donor solvent techniques are not retorting processes, as they require autoclaving and do not operate under destructive distillation principles. They have, however, been included in this section of the report, which deals with surface retorting because they operate at high temperature and should be included in any process-selection review for the development of Ontario oil shales.

In the following sections, reference to Fischer Assay (**FA**) oil and gas yields and thermal efficiency are made to determine the applicability of the various retorting processes to low oil yield shales such as those of Ontario. FA is accepted worldwide as a cost effective laboratory procedure to investigate oil- and gas-yielding potential under destructive distillation. The procedure normally used is that of the American Society for Testing Materials, Test Designation D3904-80.

There are as many definitions of thermal efficiency as there are processes for liberating thermal energy. For the purpose of this study, thermal efficiency is defined as:

$$\frac{Hvm}{(Hr) + (Pe)} \times 100$$

where: **Hvm** is the heating value contained in products delivered to markets; **Hr** is the heating value contained in the raw shale; and **Pe** is the energy equivalent used in the process.

6.2 TYPE I RETORTS

6.2.1 GENERAL

Type I retorts were the earliest experimental and commercial retorts developed. They are of simple design and operate in batch, semi-continuous and continuous modes. The most common ones are the Fischer and Pumpherston retorts.

6.2.2 FISCHER RETORT

The Fischer retort (Figure 6-2) is a laboratory apparatus consisting of a thick-walled pot with the top bolted down over a gas-tight gasket. The pot is connected to a centrifuge tube sitting in an ice-water bath and the tube is connected to an ice-water reflux condenser. Heat, applied through the wall, decomposes the kerogen and produces hot hydrocarbons and steam that condense into the centrifuge.

The only advantage of the Fischer retort is its simplicity. Disadvantages include:

(1) low organic carbon conversion, especially for shales having Types II to III kerogen, or a H : C atomic ratio less than 1.8 : 1;
(2) no recovery of the organic carbon in the spent shale;
(3) no recovery of the sensible heat in the spent shale; and
(4) batch operation.

While the Fischer retort is a cost-effective laboratory apparatus, it is inefficient and has no application for commercial-scale production of liquid and gaseous hydrocarbons.

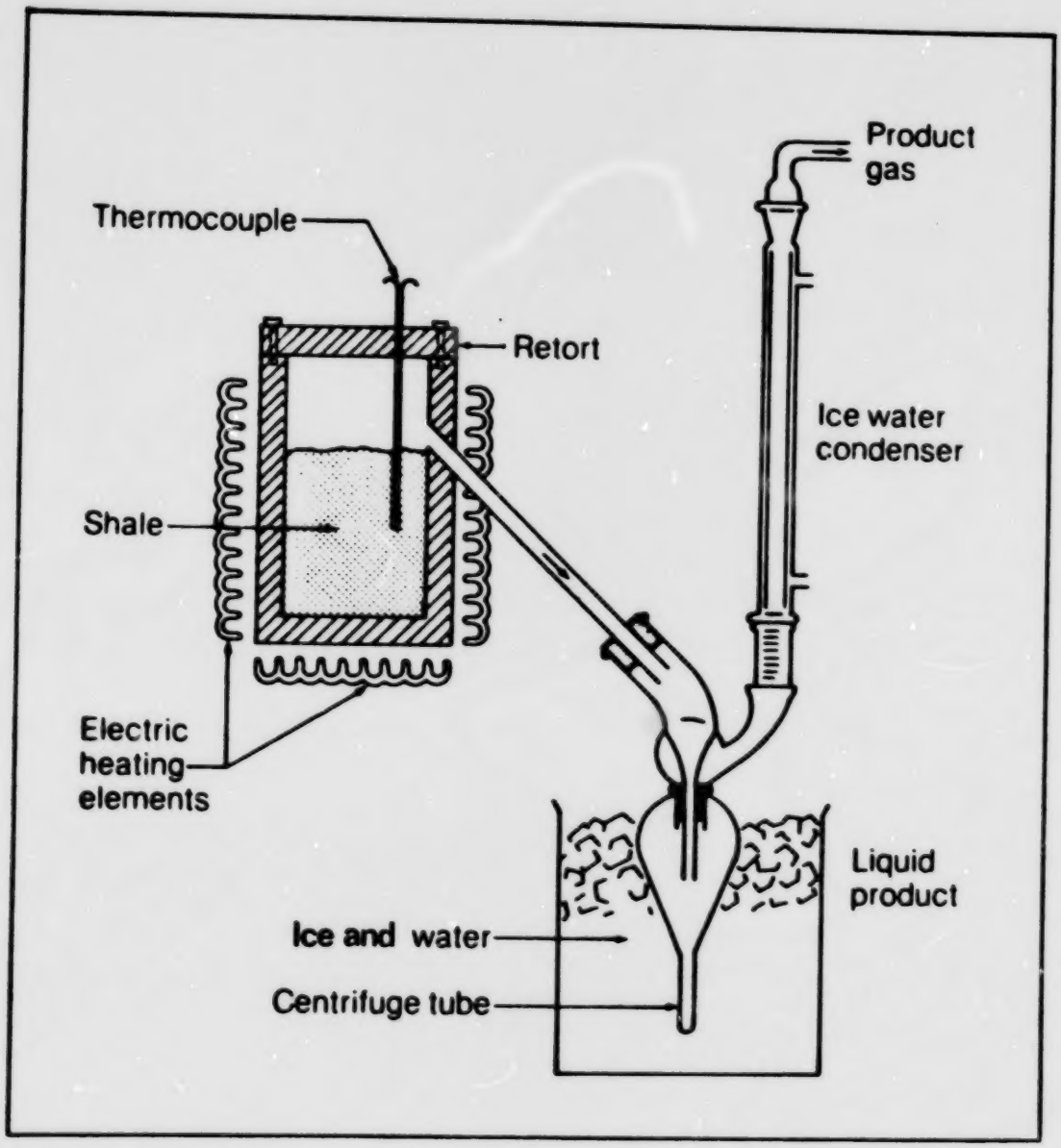

FIGURE 6-2: Fischer Assay retort (a Type I retort).

6.2.3 PUMPHERSTON RETORT

The Pumpherston or Bryson retort (Figure 6-3) was originally developed for the high-yielding Scottish torbanites, also called brown coal or oil shales, and is no longer in use. The process consisted of a large fire-brick work in which were located, from top to bottom, a cast-iron retorting chamber, followed by a gas-making chamber and a spent-shale cooling chamber, both made of fire-brick. Heat was supplied through the walls of the chambers by combusting gases in the annular space between the chambers and the outside wall of the vessel. Crushed oil shale was fed continuously to the top of the retort through a locking hopper. The column of shale in the retort was supported by a disk located at the bottom. The disk had large openings and was rotated at regular intervals to discharge the spent shale. The cast-iron retorting chamber was heated externally to a dull red (about 480°C) and the evolved hydrocarbons produced by heat exchange were removed by an upward flow of gases coming from the gas-making chamber. These latter gases were made by reacting the residual carbon of the spent shale with air and steam at about 700°C. The reaction produced chemical water, hydrocarbon gas (high calorific value), hydrogen, and ammonia (an important byproduct of the Scottish operations). The flushing gas and the evolved hydrocarbon vapour were sent to a condenser. The condensed hydrocarbons and water were sent to an ammonia scrubber. Part of the non-condensable gas was recycled to the combustion chamber, the remainder being product gas.

Advantages of the Pumpherston retort were:

(1) utilization of some of the residual carbon in the gas-making chamber and of the sensible heat in the cooling chamber;

(2) utilization of evolved gases to assist in heat distribution;

(3) production of its own energy to maintain retorting by burning off-gas from the process;

(4) production of large quantities of ammonia;

(5) utilization of cost-free gravity to feed and unload the retort; and

(6) the process was mechanically simple and not capital intensive.

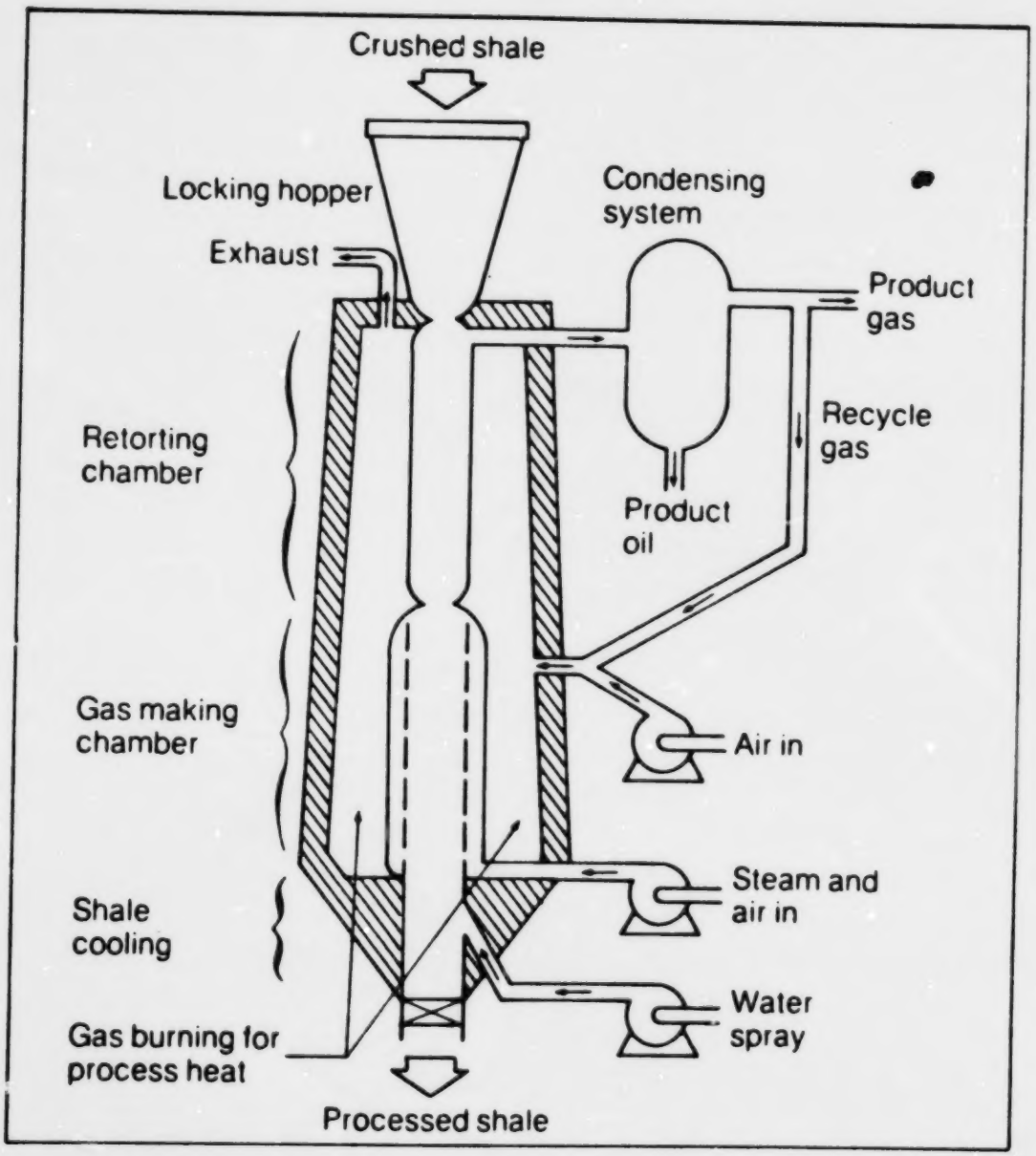

FIGURE 6-3: Pumpherston retort (a Type I retort; source: Atwood 1980).

The main disadvantages were:

(1) fines had to be removed to permit gas flow; and
(2) the total yields, that were at 93% of FA for the Green River shale.

We have not located documents comparing its yields with those of the Fischer retort on other shales. However, we believe that the use of high-temperature steam may increase Ontario shale oil yield versus those of FA (see Section 6.6).

A modern large-scale version of the Pumpherston retorts may have some long-term economic potential for Ontario shales. Retorting in the presence of superheated steam can considerably increase oil yields from shales containing kerogen with low H : C atomic ratios.

6.3 TYPE II RETORTS

6.3.1 GENERAL

In Type II retorts the retorting heat is generated internally by combustion of non-condensable retort gases and the residual organic carbon in spent shale. Three major models are under development in the USA, namely, Circular-Grate, Near-Surface retort (NSR), and Flash Hydropyrolysis. The first two have continuous operation; the NSR retort uses a batch operation. All three were originally developed for the high-yielding Green River shale.

6.3.2 CIRCULAR-GRATE RETORT

Superior Oil and Dravo have independently developed Circular-Grate retorts (Figure 6-4). The retort is a partitioned, doughnut-shaped vessel, with an internal travelling grate on which continuously-fed 6–100 mm oil shale is heated to retorting temperature. Residual carbon is combusted and, finally, the spent shale is cooled. The retorts are amenable to the addition of compartments for drying and preheating fresh shale, recycling off-gases as coolant, and/or air-cooling of spent shale. The

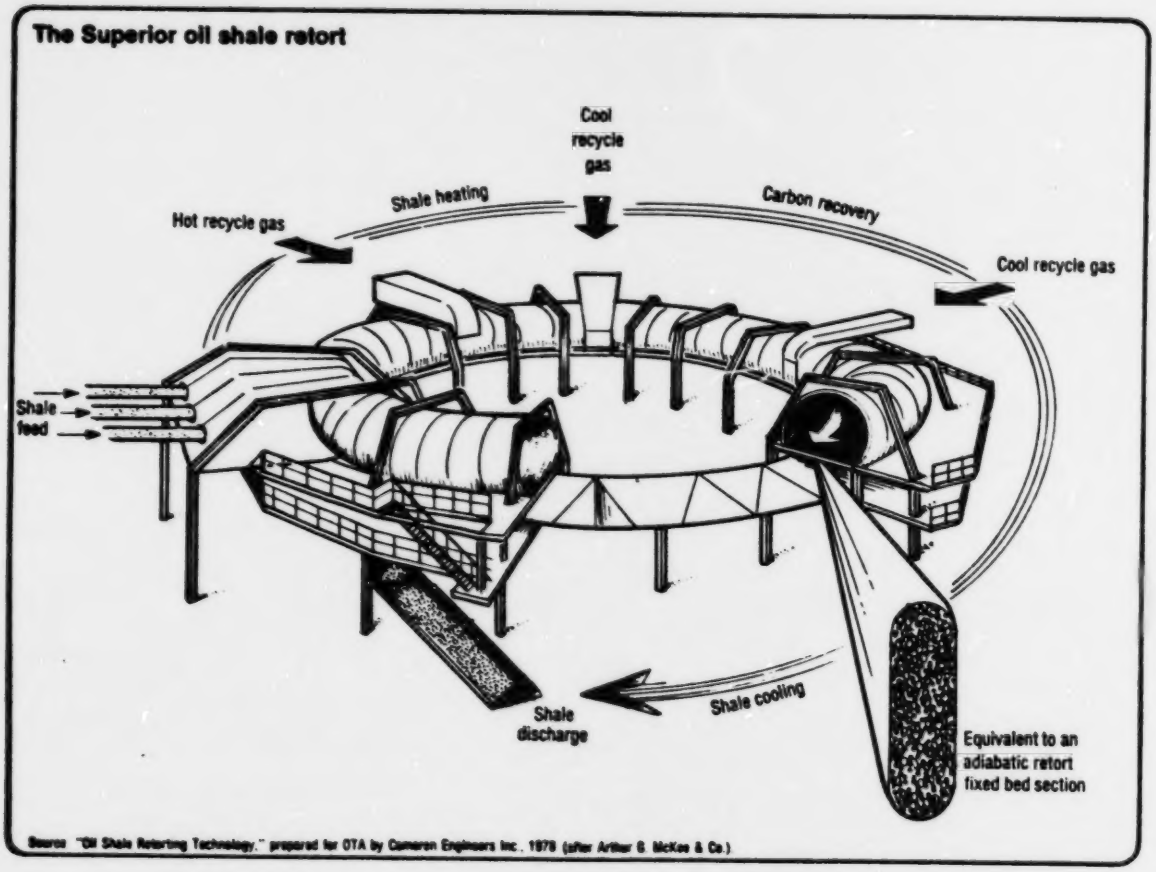
The Superior oil shale retort
Cool recycle gas
Shale heating
Carbon recovery
Hot recycle gas
Cool recycle gas
Shale feed
Shale discharge
Shale cooling
Equivalent to an adiabatic retort fixed bed section
Source: "Oil Shale Retorting Technology," prepared for OTA by Cameron Engineers Inc., 1979 (after Arthur G. McKee & Co.)

FIGURE 6-4: The Superior circular-grate retort (source: Engineering and Mining Journal 1981).

retorts may operate in direct or indirect mode, with the former having slightly higher thermal efficiency, liquid and gas yields, residual carbon utilization, and recovery of sensible heat.

Oil yields from Green River shale are equivalent to 98–100% of FA and the thermal efficiency is 80–85%. The Dravo system incorporates an agglomerating section that permits retorting of the fines and improves hydrocarbon yields by some 15%.

The raw shale oil from an Eastern shale has a 12.0 API gravity and a H : C atomic ratio of 1.42 : 1. It contains, on average, 3.86% S by weight, 100 parts per million by weight (wppm) As, and 110 wppm Fe. A corresponding synthetic crude oil would have 28.8 API gravity, H : C atomic ratio of 1.71 : 1, 0.01% S, and 1.0 wppm each of As and Fe (Venetti 1984). Upgrading tests to premium quality synthetic crude oil were conducted using the Gulf Shale Oil Hydrotreating Process.

Hydrotreating produced a synthetic crude oil that could most likely blend with petroleum crudes and be tailored to meet a particular refiner's processing schemes (Lyzinski and Jones 1984). The full-range synthetic crude oil has a total nitrogen content of 480 wppm, and all measurable arsenic, iron and ash have been removed (Forbes et al. 1983). The naphtha should be easily processed in an existing refinery's naphtha pretreater and reformer. Predicted C5+ reformate reaches over 85 vol% when an 85 MON clear gasoline is produced. The kerosene fraction did not meet Jet-A specifications due to excessive aromatic content. The distillate fractions should yield a high volume of quality diesel fuels of a cetane index of about 41. The 345°C+ residual may be acceptable FCC feedstock, but sulphur (180 ppm) and nitrogen (800 ppm) contents are quite high. In MAT tests, the synthetic crude oil compares quite favourably with light sweet USA crudes, such as South Louisiana (Lyzinski and Jones 1984). The primary products of refining the synthetic crude oil could be N°. 2 fuel oil, lesser amounts of gas oil and naphtha, and a minor (5 vol%) residual fraction (Venetti 1984).

The advantages of using a Circular-Grate retort are as follows:

1. Heat is derived from internal combustion of the residual carbon in the spent shale and is carried by circulating off-gases.

2. It has wide flexibility and is adaptable to other oil shales, coal and tar sands.
3. It provides for good control on operating temperature.
4. It is easy to operate and neither start-up nor shut-down require the vessel to be emptied.
5. Large-scale circular-grates exist in the iron industry, where they are used for sintering iron ore, indurating iron ore pellets, and cooling iron ore sinter; thus, the grates have operated in worse heating–cooling conditions than could be expected from the retorting and combusting of oil shale.
6. The retort is air tight and acceptable environmentally.

Four disadvantages are:

1. Removal of the fines is required to permit gas flow and heat transfer.
2. Yields from shale processed in Circular-Grate retorts are equal to FA; therefore, only low organic carbon conversion to shale oil would be obtained with Ontario shales.
3. The off-gases are diluted with combustion gases, resulting in a complex downstream gas treatment and separation treatment, while the process gas has a low calorific value and is unsuitable as feed to a conventional hydrogen plant.
4. The use of cross-flow of solids and gases that makes them thermally less efficient than countercurrent flow.

With modifications for steam retorting, Circular-Grate retorts should have good potential for the production of liquid transportation fuels from the shales of Ontario.

6.3.3 NEAR-SURFACE RETORT (NSR)

The Near-Surface retort (NSR), proposed by Gulf Research and Development Company, is the only modern system under development that uses batch or fixed-bed operation (Figure 6-5). The concept on which the NSR is based is that it endeavours to reduce the large capital requirements and mechanical complexity of surface retorts and to improve thermal efficiency; therefore, it is most suitable for kerogen having low H : C atomic ratio. The NSR process uses six or more huge fixed-bed vessels built in surface excavations equal to the retort volume. The sides and base are bedrock (lined with refractory material) and the top is a man-made removable cover. The

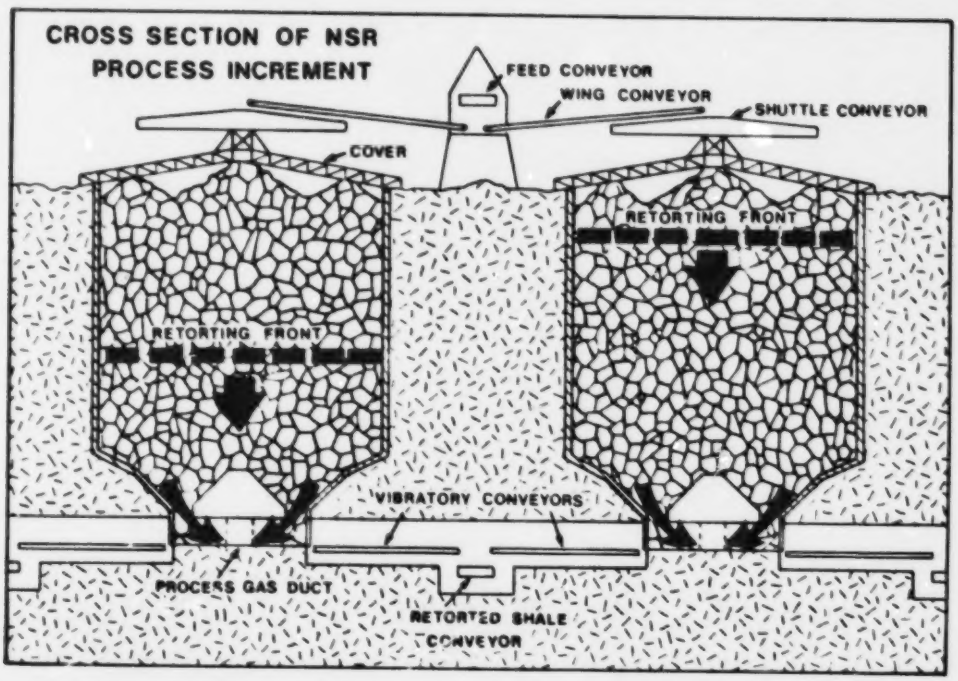

FIGURE 6-5: 90,000-tonne batch NSR retorts (Type III retort; after: Matthews 1981).

retorts are operated in succession. Each retort is filled with fresh shale, which is preheated, retorted, cooled, retrieved, and disposed. Part of the retorting heat is obtained from transferring the sensible heat of the spent shale in the cooling zone to the off-gases that are recycled into the retort or to adjacent retorts. The remaining heat results from combustion of the residual carbon in the spent shale. Evolved hydrocarbons and combustion gases are pushed downward ahead of the retorting front to preheat the shale below, and are removed continuously as liquid and gases. Spent shale is cooled and removed at the end of the cycle.

The number of retorts (six or more) permits close sizing of the crushed feed-shale for good flow of the heating gases, efficient gas–solid contact, uniform combustion and retorting, and rapid removal of the evolved hydrocarbons. Crushed fresh shale is divided into four screened fractions: the three coarser fractions (1.25–7.5 cm, 7.5–15 cm, and 15–30 cm) are sent to different NSR retorts; the -1.25 cm fraction is sent to a surface retort capable of retorting fines. The retorts proposed by Gulf would measure 45 m high by 45 m in diameter and they should accommodate some 95,000 tonnes of fresh screened shale. The tonnage in each retort is about half of that proposed in the Cathedral Bluff MIS system (Section 5.3.1). However, because of the close sizing of the crushed shale, the retorting front would advance at a rate of 1.5 m/hr versus the 0.3–4.5 m/day experienced in the MIS system. The yield obtained in the NSR should also be higher.

The NSR process has only reached the conceptual stage and its envisioned advantages would be:

(1) lower capital and operating costs;

(2) high thermal efficiency (greater than 80%) and reduced heat loss through the walls of the retort, especially in the colder climate of Canada;

(3) minimized abrasion of the larger oil shale lumps and reduced dust formation by the use of fixed-bed retorting;

(4) a more uniform porosity and permeability in the retort by separating the feed in size-fractions, thus resulting in better contacting between the shale and the hot retorting gases; and

(5) a fast-moving retorting front that reduces the required number of retorts.

The disadvantages would be:

(1) low oil yields from the low H : C atomic ratio kerogen; and

(2) the necessity of removing of the fines, sending them to a surface retort for processing. These fines could represent 20% of the mined shale.

Provided the NSR is adaptable to retorting in the presence of superheated steam, its projected low capital cost could have long-term economic potential for the production of synthetic liquid transportation fuels from the shales of Ontario.

6.3.4 FLASH HYDROPYROLYSIS

Flash Hydropyrolysis (FHP) is a process which is under development by the Energy Systems Group of Rockwell International Corporation (Figure 6-6). FHP incorporates fluidized bed technology, hydrogen retorting and internal combustion. Oil shale is ground to 70% finer than 75 µm and is dense-phase fed into a compact, entrained-flow reactor, together with carbon dioxide and small quantities of heated (to 800°C) hydrogen. The atmosphere inside the reactor is maintained at a moderately elevated pressure of 7,000 kPa (1,000 psig).

The finely ground shale particles are then heated by partial combustion of the introduced hydrogen to an operating temperature of 650°C. The heating rate is extremely rapid (about 27,750°C/sec) and temperature of pyrolysis is obtained in much less than a second. The rapid rate of heating creates instantaneous pyrolysis of the kerogen and the evolved gaseous hydrocarbons are immediately removed by the carrying gas. Rapid cooling from 650°C to 500°C is accomplished by heat exchange with recycled hydrogen at the exit of the reactor. This procedure stops high temperature chemical reactions that occur in the reactor and results in the recovery of part of the sensible heat of the spent shale. The solid spent shale is then separated from the gaseous phase by a series of high-efficiency cyclones. The solid spent shale is cooled to 95°C and discarded. The gaseous phase is cooled to 95°C in a heat recovery/liquid separation system. The separated raw shale oil is sent to a hydrotreating facility operating at 14,000 kPa (2,000 psig) and, after further cooling to 37°C, the gas is sent to a purification section.

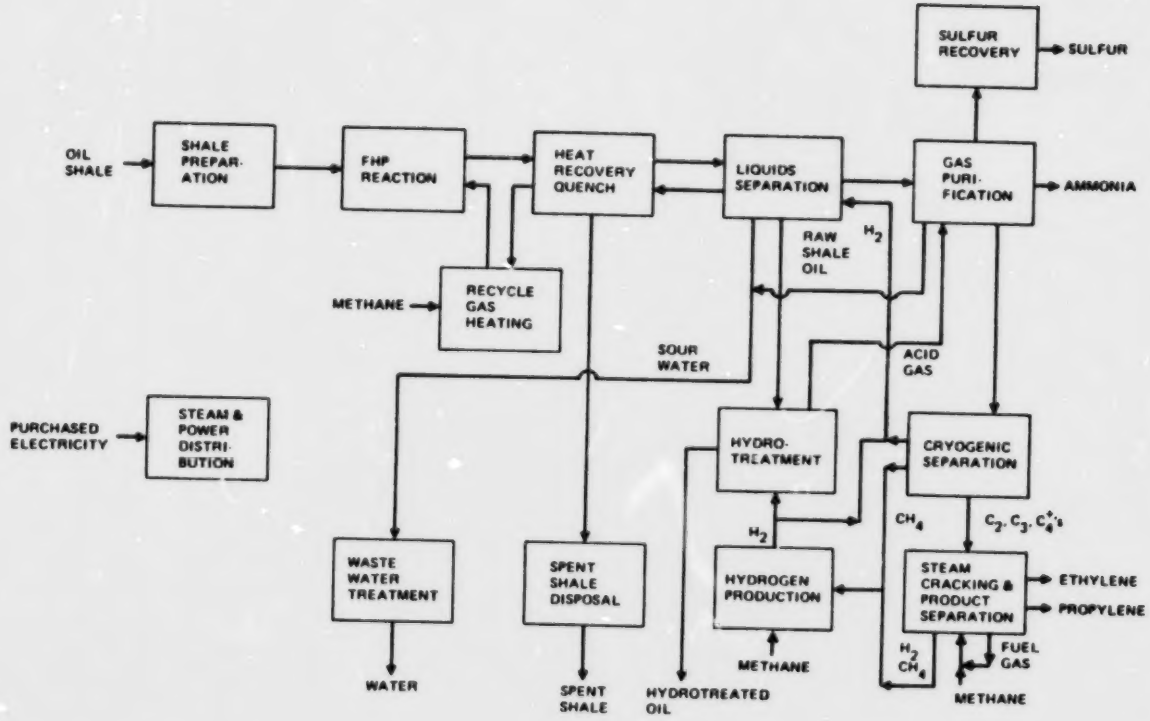

FIGURE 6–6: Rockwell flash hydropyrolysis proposed commercial plant (a Type II retort; source: Kahn et. al. 1984).

For the non-calcareous Eastern USA oil shales, one of the main advantages of the FHP process is that, because of the very short retention time, the retorting reactor operates under conditions of low chemical severity. It also favours maximum production of liquids. Non-fluidized-bed processes have long residence times, resulting in moderately high chemical severity that favours polymerizing, liquid fragmentation and/or hydrocracking of liquids, and maximum production of gaseous products. The second main advantage is the presence of hydrogen, which should improve organic carbon conversion of the low H : C atomic ratio kerogen in the shales. Carbon conversion as high as 70% was achieved with high liquid-to-gas yields and oil yields are expected at 160% of FA. However, for calcareous shales such as the Collingwood, the partial combustion of the hydrogen in the retorting zone may create very high temperature of very short duration. This could cause carbonate decomposition and high chemical severity, which could be counterproductive to the beneficial effect of the hydrogen.

Flash Hydropyrolysis should give much higher yields than FA and has a high potential for the production of synthetic transportation fuels from the shales of Ontario.

6.4 TYPE III RETORTS

6.4.1 GENERAL

Type III retorts use externally heated gases or liquids to supply the retorting heat; that is, they have an indirect heating mode. Currently, seven main technologies are under development and all have continuous operation (moving-bed). They are: Union 'B', Paraho CH, Petrosix, fluidized bed, HYTORT, and thermal solution and hydrogen-donor solvents. The first three were developed for shales having high H : C atomic ratio: the Union 'B' and the Paraho CH for the Green River shale of Western USA and the Petrosix for the Irati shale of Brazil. HYTORT is being developed for the Eastern USA shales, which like the shales of Ontario, have kerogen with low H : C atomic ratio.

6.4.2 UNION 'B' RETORT

In the Union Oil Company Union 'B' continuous retort (Figure 6-7), crushed and sized oil shale is fed at the bottom, through an oil trap. It is pushed upward, retorted by downward, incoming hot gas, and discharged from the top. Here, any sinter aggregates formed during retorting are broken up by a rotating rake. Feeding is accomplished by a rock pump consisting of two piston-and-cylinder assemblies that alternate in feeding the shale upward into a retort shaped like an inverted cone. The bottom of the retort is a double-wall cone. The inner wall has narrow slots through which evolved hydrocarbons are discharged. The bottom is also a preheating zone, in which the incoming cold shale is used to condense some of the hot hydrocarbon vapours. Part of the product gas is recycled through a heat exchanger to provide heat for the retorting process. The product, liquid oil, collects in the annular section just below the slotted wall. The retorting zone always remains at a constant level.

When Green River shale is processed in the Type 'B' retort, oil yield recovery is equal to FA and a syngas of calorific value equivalent to natural gas (about 30 MJ/m^3) is produced. Thermal efficiency is about 80% and some 4% of the organic carbon is left as residual carbon in the spent shale.

An earlier direct-fired pilot-scale Type 'A' retort was operated from the mid-1930s to the early 1950s. It was eventually abandoned because modifications that were introduced to improve on the low thermal efficiency resulted in a greatly complicated process. The Type 'A' retort, which used internal combustion of residual carbon to provide retorting heat, had low thermal efficiency, oil yields at about 80% of FA, and high combustion heat that decomposed carbonates, produced carbon dioxide and monoxide gases that diluted the off-gases to low low-calorific value. The high heat of combustion also induced coking and agglomerated the combusted shale.

The construction of a 1,600 m^3 (10,000 bbl) per day shale oil Type 'B' retorting plant was completed in September 1983. It has not reached sustained production, as of June 1985, primarily because of problems with the system for cooling of retorted shale. Major problems with agglomeration and sintering have been encountered.

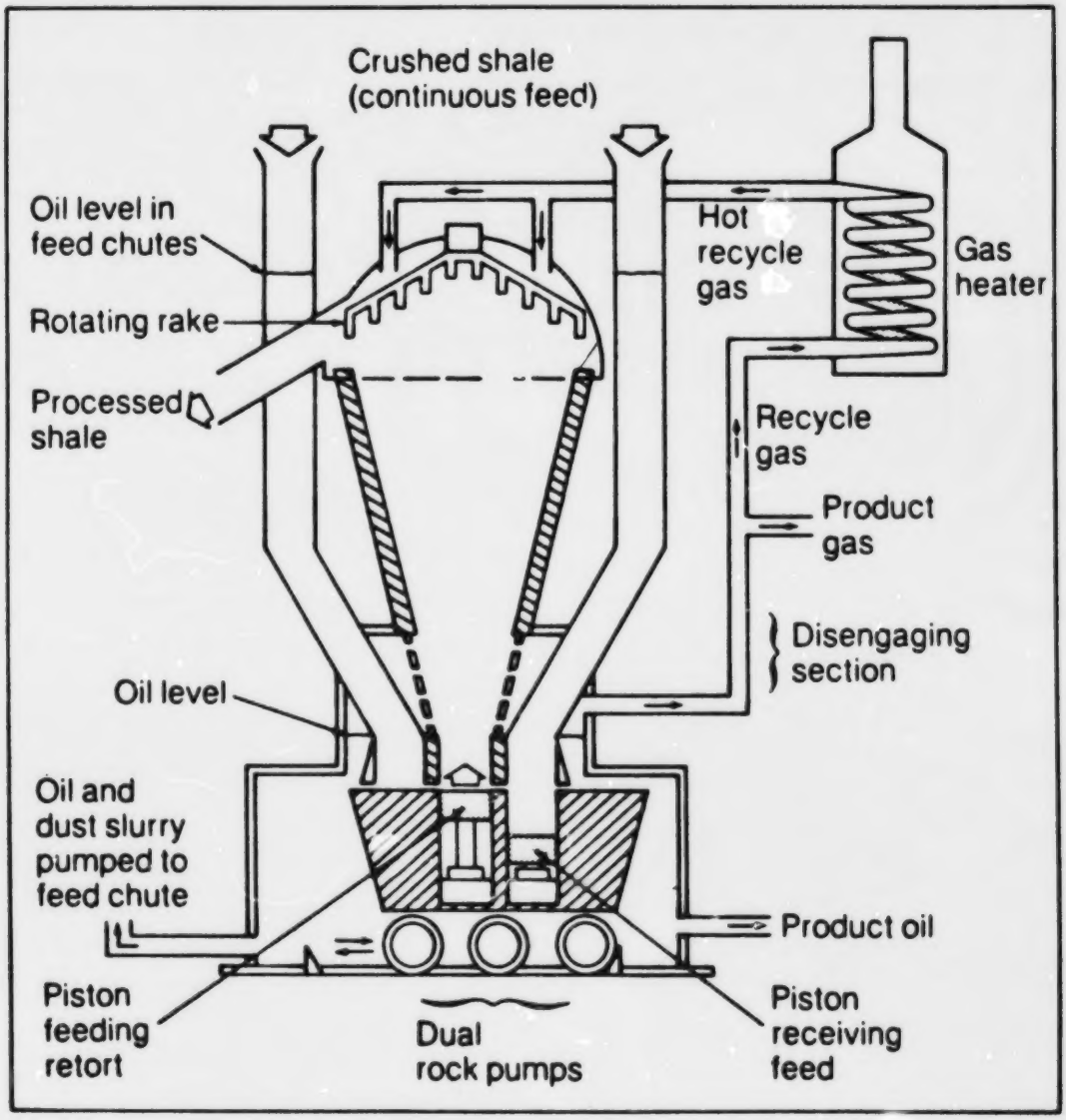

FIGURE 6-7: Continuous-feed UNION 'B' retort (a Type III retort; source: Atwood 1980).

Using the retorting parameters of Section 5.2 and comparing with data from other retorts, some advantages and disadvantages may be inferred with respect to processing of Ontario shales in Union 'B'-type continuous retorts.

The advantages could be as follows:

1. There is a countercurrent flow of gas and solid.
2. The retort design, with its reverse-cone shape and retorting front at the top, reduces rock pressure and helps in liberating the evolved hydrocarbons from the individual shale particles.
3. The action of the rock pump vibrates the retorting bed which mitigates the effects of agglomeration and bridging.
4. The condensed shale oil is contacted with incoming raw shale, resulting in cooling and removal of particulates from the shale oil.
5. An off-gas product with a high calorific value is recovered.

The disadvantages would be:

(1) oil and gas yields that could equal FA at best;
(2) low organic carbon conversion;
(3) low overall thermal efficiency; and
(4) high content of residual carbon left in the spent shale.

6.4.3 PARAHO (CH) RETORT

Paraho Combined Heated (CH) retort (Figure 6-8) is a modification of the Direct Heated (DH) retort developed for Western USA shales. It was modified to recover the thermal energy of high residual carbon left in the spent shale from Eastern USA oil shales. In the CH retort, screened fresh shale is fed by a rotating continuous-feed distributor at the top of the retort and proceeds downward by gravity. At the bottom of the retort, a moving grate mechanism discharges the spent shale. The retort is compartmented into an upper retorting zone and a lower combustion zone, separated by an internal seal that allows the shale to flow, but prevents combustion gases from flowing into the retorting zone.

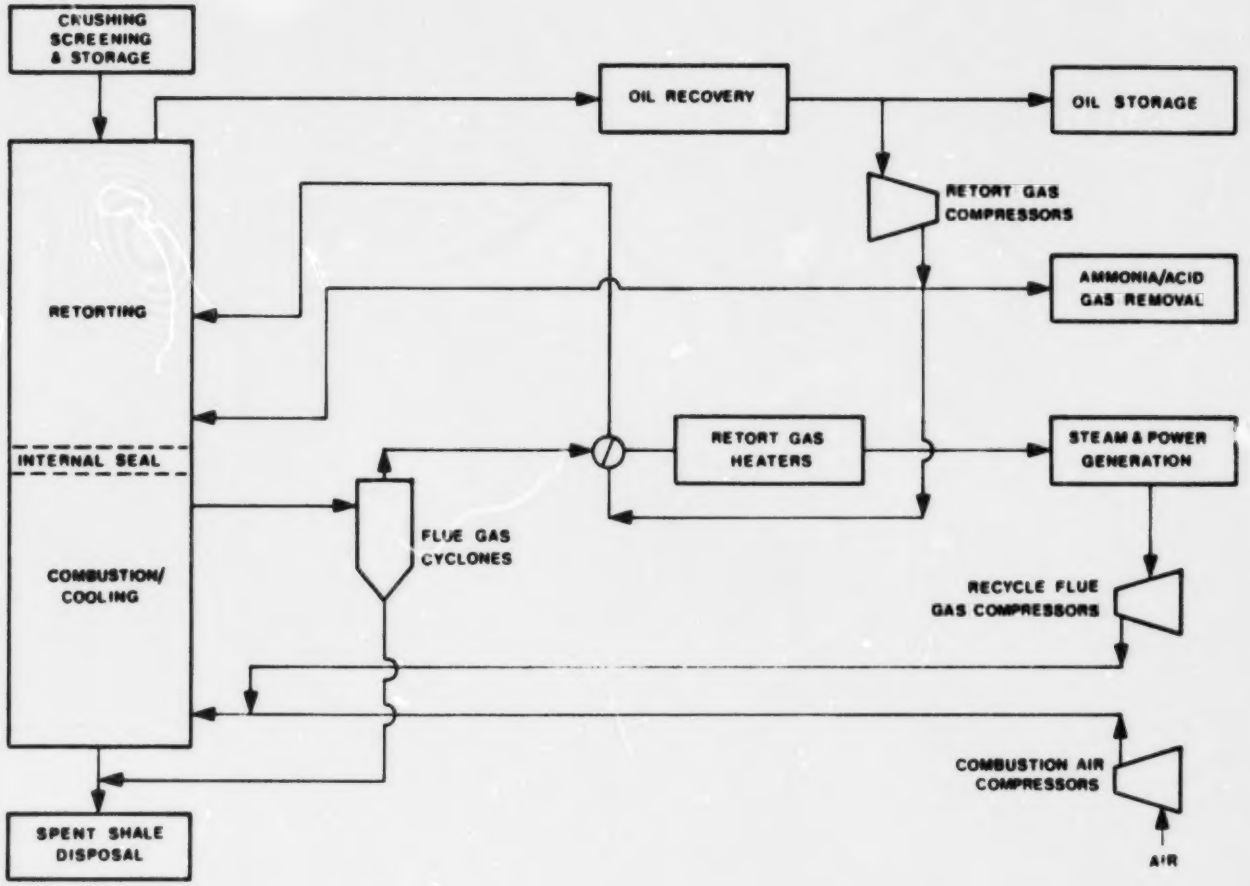

FIGURE 6–8: Paraho CH process (a Type III retort; after Vyas 1981).

The combustion zone is maintained by a mixture of air and recycled retorting product gas. The sensible heat of the combustion gas is recovered in an externally located heat exchanger that is used to heat part of the product gas that is recycled to the retorting zone as heat carrier. The separation of combustion gas and retorting gas results in a product gas with a high calorific value. Hydrocarbon vapours rise countercurrently to the descending raw shale and preheat the latter while condensing into an oil mist. The mist is carried by non-condensable gas and, after passing through a cyclone for dust removal, is directed into a hydrocarbon recovery unit. The raw shale, fed at the top, is preheated, retorted, combusted, and cooled in its downward course.

Tests conducted on Kentucky shale yielding 52.2 L/t (12.5 US gal/ton) indicated that the CH process should yield 60.9 L/t (14.6 US gal/ton) of liquid hydrocarbon as shale and light oils. A 30,000 ton/d plant would produce 8,100 bbl/d of shale oil, 2,300 bbl/d of light oil, 14,500 scfm high calorific value gas, and about 48.3 MW of excess power. About 64.8% of the energy output would be liquid products, 21.6% high calorific value gas, and 12.1% excess power. The quality of the liquid products is not described. Using 100% equity, 12% internal rate of return and credits for byproducts (Vyas et al. 1981), a liquid-production cost of US $42.50/bbl (1980 dollars) was indicated.

The main advantages of the Paraho CH retort are:

(1) gravity feed and a simple configuration that lowers capital investments and operating costs;

(2) countercurrent flow for better and cheaper heat exchange;

(3) recycling of the sensible heat of the spent shale;

(4) combustion and gasification of the residual carbon and part of the off-gas to provide retorting heat (an asset for Ontario shales where the residual carbon may represent about two-thirds of the latent energy);

(5) production of a high calorific value off-gas, with quality sufficient for the manufacture of hydrogen for shale-oil upgrading; and

(6) fairly high thermal efficiency (85%) for Eastern USA shales.

Some of the disadvantages are:

(1) removal of the fines (-6.5 mm), by screening, means that less than 90% of the mined shale is retorted; and

(2) oil yields equivalent to 117% of FA.

The various retort models developed by Paraho have low potential for the production of liquid transportation fuels from the shales of Ontario, unless they can be modified to operate with superheated steam.

6.4.4 PETROSIX RETORT

Petroleo Brasiliero S.A. (Petrobras) developed the Petrosix process for the medium- to high-yielding Irati oil shale. The process (Figure 6-9) uses a vertical gravity-flow indirect-mode retort and accepts raw shale feed ranging in size from 1.5 to 15 cm. The shale is fed from the top through a hopper and shale distributor. The retort operates slightly above atmospheric pressure and uses an upward flow of recycled gas, as a heat carrier and as a flushing fluid, countercurrent to the downward flow of the shale. Cold recycle gas enters at the bottom to cool the spent shale and to recover sensible heat. Hot recycle gas enters at the middle. Both streams combine and flow upward providing the retorting heat. Evolved hydrocarbons are entrained and condensed on the incoming cold shale. An oil–water–gas mist forms and is carried out. Dust and large droplets are removed by cycloning, the fine droplets being removed by an electrostatic precipitator. The cleaned gas is compressed: one part goes to product recovery, the remainder is returned to the retort.

The Brazilians have been operating a 2,200 ton/d prototype mine and process pilot-plant since 1972. After more than 65,000 hours, the plant is still the largest operating plant in the Western Hemisphere. In mid-1982, Petrobras announced that it was going ahead with the construction of a single industrial module capable of retorting 7,800 ton/d of shale and of yielding 2,390 bbl/d of low sulphur fuel oil, 260 bbl/d of naphtha, and 52 long tons per day of sulphur. We have been unable to determine the present status of the project.

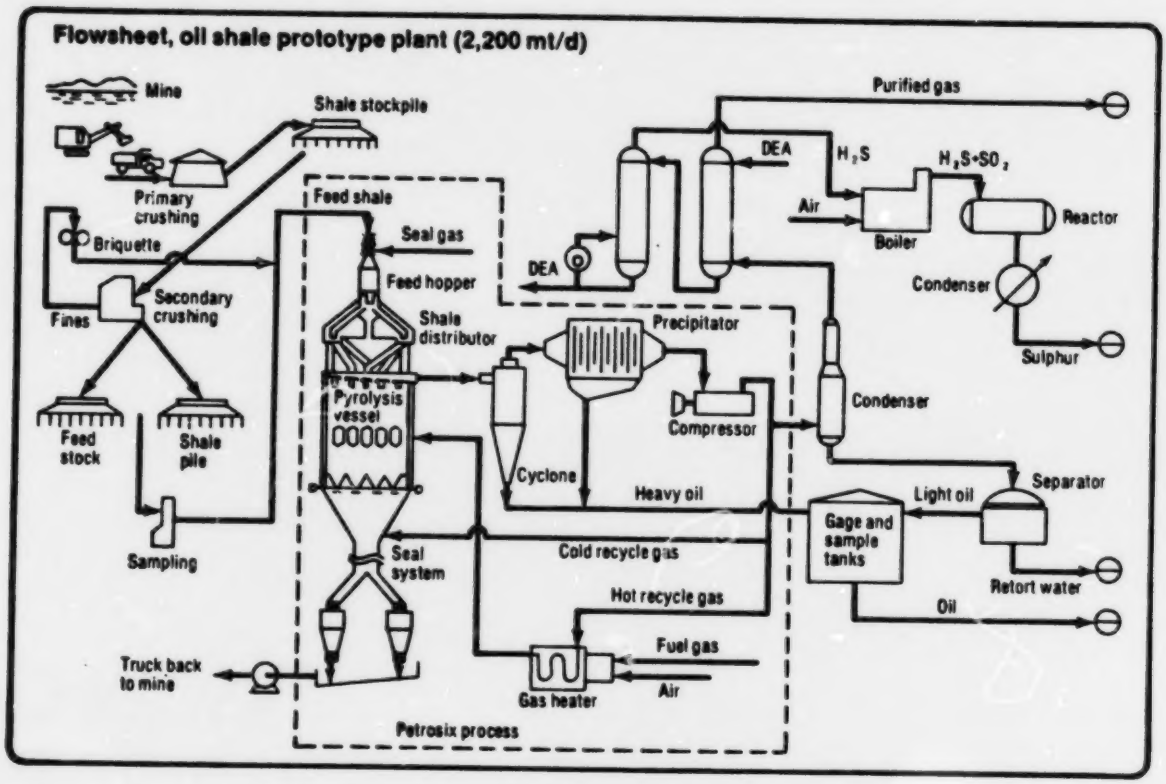

FIGURE 6–9: Petrosix prototype oil shale process (a Type III retort; source: Engineering and Mining Journal 1981).

The Brazilians have tested some of the Eastern oil shales for American Syncrude Corporation, but very little of the test data have been published. The present concept is for a facility consisting of two industrial-size retorts capable of treating 15,000 ton/d of raw shale, to yield 4,160 bbl/d of crude shale oil, 10.3 million scf high calorific value gas, and 86 long tons of sulphur. These data indicate an industrial yield of about 45.9 L/t (11 US gal/ton) raw oil, which is slightly below FA yields for Kentucky shale. Quality of products is unknown to us, and advantages and disadvantages can only be inferred.

Advantages of the Petrosix are:

1. Retorting in a single vessel results in capital cost savings.
2. Gravity-flow and process simplicity result in lower operating costs.
3. The process has been thoroughly tested in large pilot-plant operation.
4. High calorific value off-gas is produced.
5. Countercurrent flow of solid and fluids result in high thermal efficiency.

Disadvantages, for Ontario shales, are:

1. Oil yields, at best, are equal to FA.
2. Pre-sizing of the feed, to permit good contacting heat transfer and circulation of fluids, may result in up to 20% of the mined shale not being retorted unless an agglomeration plant is added.
3. About two-thirds of the organic carbon would not be converted and the latent thermal energy of the residual carbon would be wasted.

The Petrosix retorting process has little potential for the production of transportation fuels from the shales of Ontario.

6.4.5 FLUIDIZED BED RETORTING

Bench-scale fluidized bed retorting (FBR) was conducted at the Kentucky Institute for Mining and Minerals Research (IMMR) and by others to show the combined effects of rapid heating and high sweep-gas velocity. FBR, with an inert fluidizing fluid at a bed temperature of 550°C, has shown that Eastern USA oil shales, subjected to rapid

heating rates of up to 20,000°C/min, have increased liquid yields to 135–155% of FA while gas yields decrease accordingly. An organic-carbon conversion of 55% was achieved, compared to the usual 30–40% under FA.

Increased oil and gas yields and higher organic carbon conversion are definite advantages of FBR.

The disadvantages include:

(1) the possibility of excessive particulate contamination of the products by using a fine-grained feed;

(2) the poor quality of the shale oil produced in bench-scale testing (a lower H : C atomic ratio than most retorting systems);

(3) the necessity of developing reactors; and

(4) unknown quantity and quality of products.

Fluidized bed retorting ranks among the best systems for the production of synthetic transportation fuels from the shales of Ontario, because of higher than FA oil yields.

6.4.6 HYTORT PROCESS

Retorting in the presence of hydrogen in a pressurized vessel has been under investigation since the early 1950s. It has been shown to increase oil and/or gas yields considerably, especially on shales having kerogen with low H : C atomic ratio such as the Eastern USA and Ontario shales.

HYTORT, the most advanced hydrogen retorting process (Figure 6-10), is under development by HYCRUDE Corporation, a commercial subsidiary of the Institute of Gas Technology (IGT), Chicago, Illinois. In HYTORT, a gravity moving-bed of shale crushed to -2.5 cm is fed at the top of a pressurized vessel (4,100 kPa or 600 psig) and preheated by hot (375°C) recycled hydrogen flowing countercurrently. The preheated shale moves downward to the retorting zone, where it is heated at a rate of 38°C/min to a bed temperature of 565°C by contacting with hot (650°C) hydrogen. When the spent shale reaches the bottom of the retort, it is cooled by a countercurrent flow of cold hydrogen, which is preheated and sent to the top of the retort. Product gases are

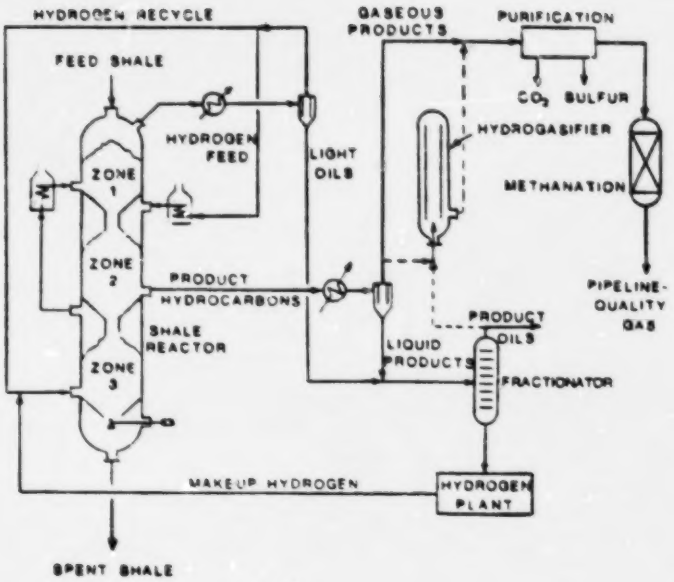

FIGURE 6-10: The HYTORT process (a Type III retort; source: TRW 1979).

stripped of water and high-temperature condensable hydrocarbons by cooling in a heat exchanger. The two liquids are then separated by emulsion-breaking. The sour gases are further cooled to remove benzene, and scrubbed of their acidic components to produce saleable ammonia and elemental sulphur.

Operating parameters can be varied to suit local conditions. For example, in an area where natural gas is inexpensive and readily available, the process can be adjusted to produce a maximum amount of shale oil. Natural gas used in the process is then obtained mostly from external sources. In other areas, operating conditions can be altered to produce more gas for recycling to the process and therefore less product oil.

When maximum shale-oil production is desired, the sweetened gas product is steam-reformed to produce hydrogen, which is recycled at the bottom of the retort. When high calorific value gas is the main product desired, the sweetened gas is catalytically hydrogenated to methane in a methanation reactor. Excess hydrogen is then separated cryogenically and recycled to the bottom of the retort for preheating by the spent shale.

The HYTORT shale oil is characterized by a low pour point and excellent storage stability. Raw oil upgraded to synthetic crude oil by conventional catalytic hydrotreating could be a good source of diesel fuels. The quality of the raw oil and its synthetic crude oil is summarized below:

	Raw Oil	Upgraded Oil
API Gravity	12–24	28–32
Nitrogen (wt%)	1.5–2.0	0.03–0.08
Sulphur (wt%)	0.8–1.3	0.002–0.005
Arsenic (wppm)	1–3	ND
Pour Point (°C)	-29– -43	-29– -43
Distillate Yield (vol % below 371°C)	65–85	80–90
Pentane Insolubles (wt%)	9	ND
Aromatics (%)	50	40
Molecular Weight	230	NA

Ewert and Scinta (1983) reports that hydrogen retorting of an Indiana shale containing 12 wt% organic carbon can yield in excess of 11 wt% oil per unit of dry shale. The raw shale oil has -37°C pour point and a good boiling range distribution, but still needs upgrading to remove heteroatoms and increase the 17 API gravity. Simulated distillation of the raw shale oil indicated by volume: 23% gasoline, 18% kerosene, 39% gas oil, and 20% residue.

The HYTORT process, developed mainly for Eastern USA shale, has been tried successfully, at the bench-scale, on two of the Ontario oil shales. Yields of more than twice FA were obtained.

Advantages of the HYTORT process include:

1. The process is specifically designed for oil shales with a low H : C atomic ratio, such as those from the eastern USA and Ontario.
2. Conversion of organic carbon to oil and gas is higher relative to FA and other processes.
3. A choice of main end-products can be obtained from predominantly shale oil to predominantly high calorific value synthetic methane gas.
4. Process parameters can be varied to suit local conditions, such as the availability of natural gas.
5. In the case of shale oil production, yields in excess of 200% can be achieved as experienced on Eastern USA shales in an adiabatic process-development unit of 0.9 t/hr capacity for runs of up to 8 hours.

6. The product oil is of good quality and reportedly should be suitable as refinery feedstock to some refineries.

Two main disadvantages are:

1. Thermal efficiency of the process is said to range from a low of 50% to 55% for maximum shale oil production from Eastern shales, to a high of 65% for maximum syngas production for Western USA shales.
2. The process is still in the early phase of development. Although US $20 million has already been expended, there are still numerous unknown and technical problems to be addressed before the project reaches commercial module-size construction.

Retorting in the presence of hydrogen, by HYTORT or other processes, can more than double FA oil yields and significantly improve the quality of the product. Testing of the HYTORT process on a variety of world oil shales has resulted in oil yields in the range of 115% up to 300% of FA yield, depending on the particular oil shale (Figure 6-11). Hydrogen retorting has the optimum potential for the production of synthetic transportation fuels from Ontario oil shales.

6.4.7 THERMAL SOLUTION AND HYDROGEN-DONOR SOLVENTS

Thermal solution or solvent extraction techniques convert the organics to soluble hydrocarbons without a gaseous distillation phase. As such, the techniques are not part of pyrolysis or retorting. They require closed-vessel operation (or autoclaving) at low and/or high temperature or pressure, and have been included with surface retorting. The techniques, under investigation since the early 1920s, are very effective in the conversion of organic materials to a soluble state but, unfortunately practical (dollar-wise) techniques of separating the solvent phase from the solid fine-grained solids have yet to be found. Nevertheless, the techniques have good potential and are reviewed here.

The Australians were first to experiment with thermal solution, by using liquid solvent extraction in supracritical conditions. Their objective was to concentrate organic matter for observation or identification in the laboratory, rather than the search for an industrial process. Dulhunty (1942) reported that:

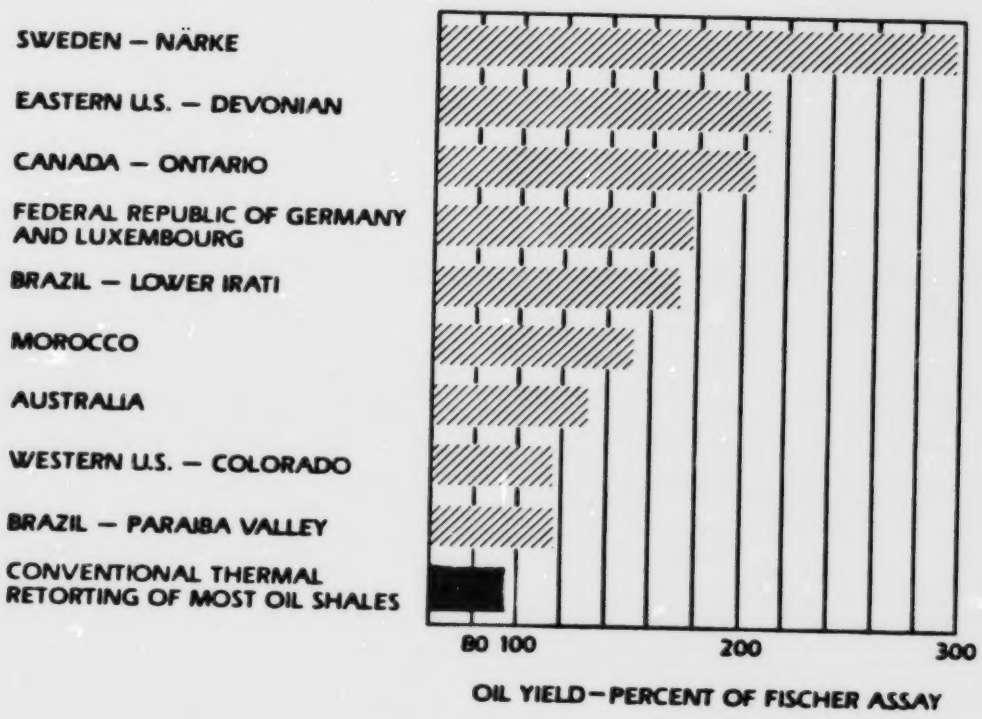

FIGURE 6-11: HYTORT yield improvements on various world oil shales (source: HYCRUDE 1984).

1. Preheating the Australian torbanite to temperatures from 350°C to 450°C in the presence of benzene rendered the organic matter highly soluble.
2. Aromatic solvents were more efficient than aliphatic.
3. Organic matter was better extracted using its own shale oil at temperatures from 350°C to 450°C and under 2,100 kPa (300 psig) of pressure (supracritical conditions).

In the early 1950s, the United States Bureau of Mines (USBM) conducted a series of tests using supra- and supercritical conditions as a means of increasing organic conversion in oil shale. The USBM experimented at bench-scale using batch, semi-continuous, and continuous operation apparatus. They investigated the effect of temperature, pressure, reaction time, type of solvent (petroleum kerosene, quinoline, anthracene oil, shale oil, etc.), inert atmosphere, hydrogen atmosphere, and richness of the shale upon the amount of organic matter extracted from high-yielding (171–221 L/t or 41–53 US gal/ton) Green River shale. In these experiments (Jensen et al. 1953), a slurry of shale oil and oil shale (sized to finer than 4.75 mm and coarser than 2.3 mm) was treated in an autoclave at temperatures of 400°C to 450°C and pressure of 2,100 kPa (300 psig). This resulted in up to 90% of the organic matter being converted to oil and gas, with combined oil and gas yields of 119% of FA. However, the thermal-solution shale oil was of lower quality due to polymerization and a higher proportion of gas was produced (cracking). Thermal solution in the presence of high partial pressure hydrogen at total gas pressure of 29,600 kPa (4,292 psig) and temperature of 450°C gave combined oil and gas yields of 126% of FA. The oil had a better quality than the solution without hydrogenation, and there was a decrease in gas and coke.

McKay and Chong (1983) conducted experiments, under supercritical conditions on Eastern USA shales, yielding 50 to 67 L/t (12 to 16 US gal/ton). Coarsely ground (-150 µm) shale was combined with various amounts and types of solvent in an autoclave operating at a pressure of 33,000–34,000 kPa (4,785–4,930 psig) and a temperature of 400°C (supercritical conditions). The solvents were mixtures of water–methanol, water–tetraline, water–toluene, or water–octanol. The best organic extraction (90 wt%) was obtained with the water–tetraline mixture; the other solvent mixtures extracted only 25–70 wt% of the organic matter. Tetraline and water

formed a dense fluid at the high operating temperature and pressure of the autoclave. Tetraline is an aromatic solvent which is known to be not only a good solvent for aromatic compounds, but also a good hydrogen-donor solvent. This latter characteristic may be largely responsible in effecting a much higher conversion than the other three solvents.

The utilization of hydrogen-donor solvents is a variation of thermal solution and is considered by many research groups (Cronauer et al. 1983, Mason 1982, and Baldwin et al. 1983) to be a practical alternative to hydrogen retorting. Hydrogen-donor solvents provide a source of hydrogen to kerogen, even in retorting at relatively low temperature and pressure. Successful bench-scale experiments were conducted on the high yielding Australian Rundle and Western USA Green River shales, and on the low-yielding Eastern USA shales. Cronauer et al. (1983) experimented on Kentucky shales, from the Cleveland Member of the Ohio Formation, containing 12 wt% total organic carbon and less than 3% moisture. A batch microreactor was charged with equal weights of shale and solvent (tetraline or mesitylene) in a nitrogen atmosphere with a starting pressure of 300 kPa or 43.5 psig (room temperature). The temperature was brought to a maximum of 450°C in 2.5 min and maintained from 0 to 30 min. The reaction was then stopped by rapid cooling (operating reactor pressure is not stated). Using the good-donor tetraline solvent, conversion of organics to toluene solubles was up to about 90% when the reaction temperature was kept at 450°C for residence time of 10–15 min. Using the poor-donor mesitylene solvent, conversion was reported to be much lower (percentage not stated). Also, conversion was related to thermal cracking so that heavier components were formed by retroactive reactions.

The advantages of thermal solution or solvent extraction are:

1. High rates of heat transfer permit shorter retention time in the reactor.
2. Up to 90% of the organic content is converted to hydrocarbon vapours on Eastern USA shales. This is comparable to hydrogen retorting and much higher than the 25–40% for FA.

The disadvantages are:

1. Fine crushing or grinding with or without sizing is required to obtain a workable slurry.
2. Some of the shale particles are disaggregated during thermal solution and smaller shale particles are produced.
3. When shale oil is used as the solvent, it is subject to cracking followed by polymerization and condensation, resulting in a lower quality product.
4. It is difficult to separate, economically, the combined solvent–product oil from the spent shale.

If low cost solid–liquid separation techniques could be developed, thermal solution, with or without hydrogen-donor solvent, would potentially be one of the best techniques for the production of synthetic transportation fuels from the shales of Ontario.

6.5 TYPE IV RETORTS

6.5.1 GENERAL

Externally heated solids are used as a heat-transfer media to supply the retorting heat in Type IV retorts. Six different models are under development. They are: Tosco HSP, Lurgi-Ruhrgas, SPHER, Battelle's MSFB, PEDCo, and Taciuk. The Taciuk process is an oil-sands treating process; it is included here as it may have application for retorting oil shales.

6.5.2 TOSCO HSP RETORT

The TOSCO Hydrocarbon Solids Process (HSP) (Figure 6-12) uses a Tosco II retort (Figure 6-13), which has been modified to burn the residual carbon of the spent shale in an external dense-phase fluidized bed combustor. The TOSCO II process was developed by The Oil Shale Corporation (**TOSCO**), which designed a pilot plant for about 1,000 ton/d. This plant was located on Parachute Creek in western Colorado and was operated at various times over a period of several years ending early in 1972. The

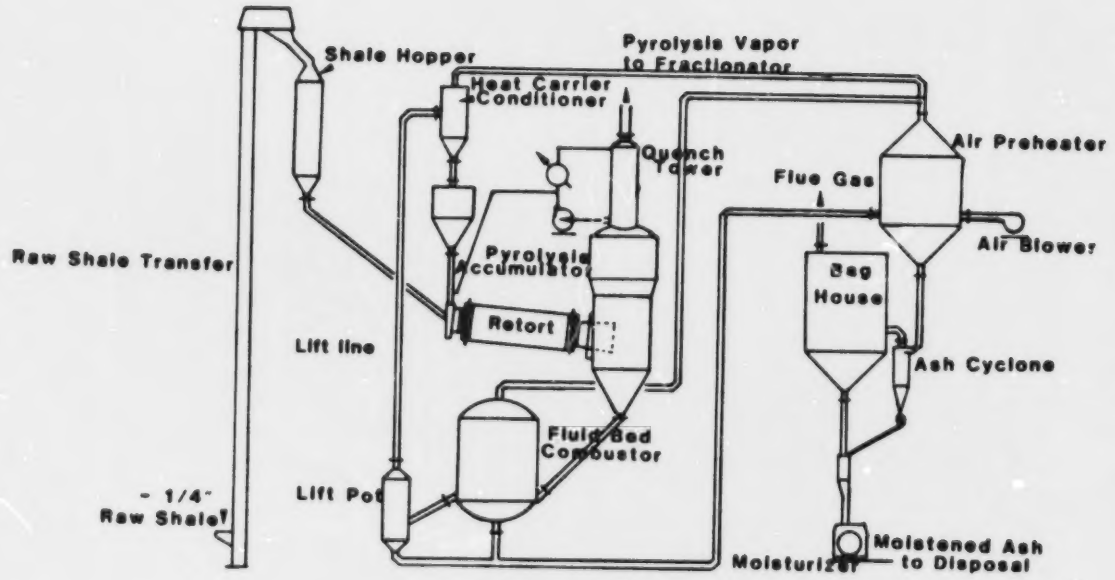

FIGURE 6–12: Flow diagram of the TOSCO HSP process (a Type IV retort; source: Pease 1981).

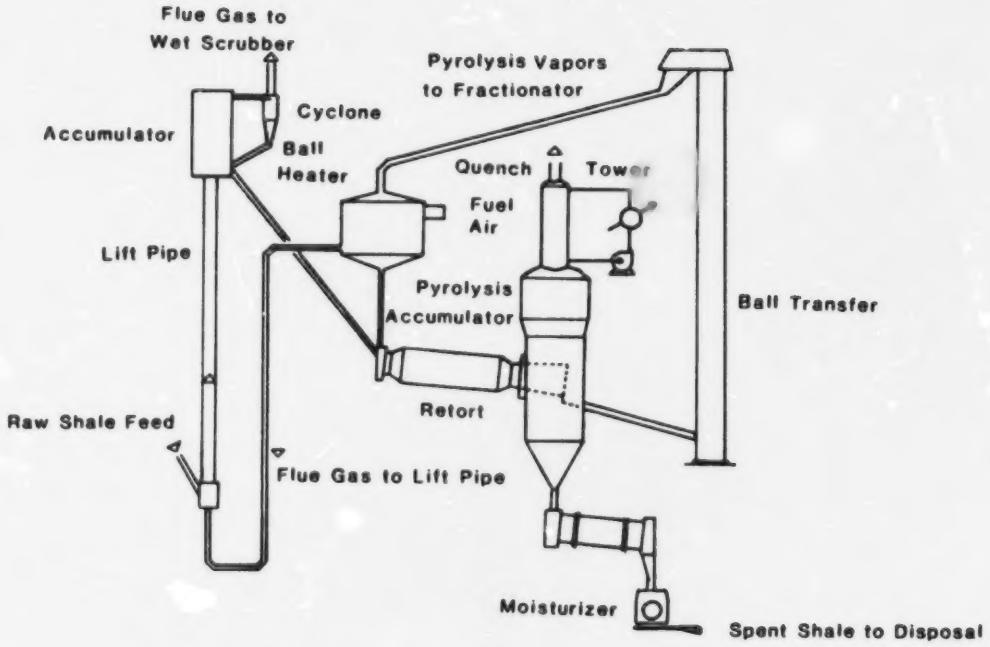

FIGURE 6-13: Flow diagram of the TOSCO II process (a Type IV retort; source: Pease 1981).

last operator prior to shutdown was the Colony Development group, with Atlantic Richfield Oil Company acting as manager for the group, which also included Standard Oil Company of Ohio, the Oil Shale Corporation, and Cleveland Cliffs Iron Company.

In the HSP retorting process, preheated raw shale is brought to temperature of pyrolysis by contacting with a hot, fine-grained heat-carrier (combusted spent shale) and a co-current flow of flushing, recycled gas. A stream of heat-carrier shale, heated to 690°C, and a stream of preheated, crushed (0.6 cm), raw shale are fed to and mixed in a rotating retort drum (kiln-type). The mix, consisting of a number of volumes of heat-carrier (to be determined) to one volume of raw shale, reaches the retorting temperature of 480–500°C as it flows through the revolving drum. The mix is constantly agitated, allowing for a high rate of heat transfer and permitting fines to be retorted. The combusted shale and new spent shale flow out into an accumulator vessel, then are fed into a dense-phase fluidized bed combustor. Burning of residual carbon reheats the heat-carrier. The bulk of the combusted dense-phase bed consisting of heat-carrier is first fed to a lift pot. It then goes to a conditioning unit, and finally is recycled to the retort. The fines from the combustor are entrained by the flue gas and transported to a heat exchanger. They are then directed to a baghouse for removal of particulates.

Evolved hydrocarbons flow from the accumulator to a quench tower, where heavy fractions are condensed and entrained particles larger than particulates are removed.

Little is known about the quantity and quality of retorting products that can be recovered from Eastern USA shale. However, oil yields are expected to reach 110–115% of FA using an oil recycle option, and API gravity should be around 18.5.

The main advantages of the process are:

1. The product gas has a high calorific value.
2. The spent shale contains residual carbon that is burned outside of the retort and there is no mixing of the flue with the evolved hydrocarbons.
3. Sensible heat is recovered.
4. The small size (-0.6 cm) of the feed permits a reduced retention time, and gives a better quality oil by reducing polymerization and cracking.

5. The revolving drum that assists contacting also increases heating rates, reduces retention time, and permits retorting of fines without preventing the flow of flushing fluid and evolved hydrocarbons.
6. It allows for good temperature control.
7. Kilns have long-established industrial records for their reliabillity and ease of operation.

The disadvantages, expecially for Ontario shales, are:

1. Yields would be, at best, 120% of FA.
2. The large volume of recycled combusted shale requires the use of a larger retort.
3. The process is mechanically complex, and appears to be capital intensive and difficult to operate.
4. The process has only attained pilot-scale capacity of 6 ton/d.

The Canadian Taciuk process, described below in Section 6.5.7, uses the advantages of the revolving drums and appears to be less complex, and less capital intensive than the Tosco HSP process. The various Tosco retorts have low potential for liquid fuels production from the shales of Ontario.

6.5.3 LURGI-RUHRGAS RETORT

In the Lurgi-Ruhrgas oil shale retort, a fine-grained portion of the spent shale is used as a solid heat carrier. A solid stream of hot spent shale is intimately mixed with fresh, finely crushed (-4 mm) shale by a horizontally rotating screw-mixer located in the retort. The mix consists of seven volumes of spent shale for one volume of raw shale. The mixing action is conducted throughout the whole length of the retort and is completed in a surge bin at the end, where a fraction of the spent shale is recycled and the rest discarded. The spent shale for recycling is sent by a lift pipe to a solids heater, where heat is supplied by fluidized bed combustion of the residual carbon and additional fuel (Figure 6-14).

The process was not tried on Eastern USA shales and the quality and quantity of products is unknown.

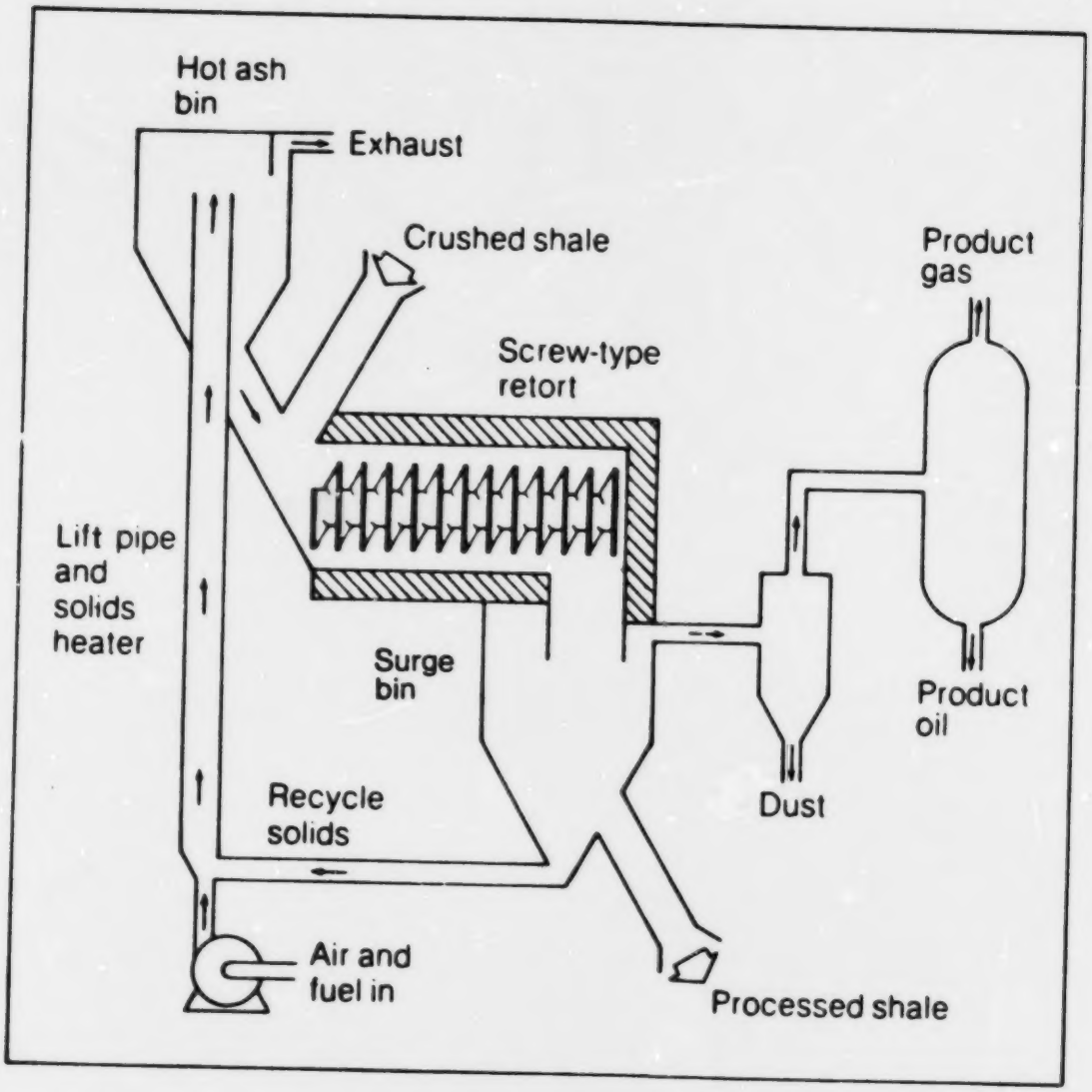

FIGURE 6-14: Continuous-feed Lurgi–Ruhrgas retort (a Type IV retort; source: Atwood 1980).

The Lurgi-Ruhrgas process is an oil-shale adaptation of a coal-fines gasification process and of a hydrocarbon-cracking process for the production of olefin and town gas.

The main advantages are:

1. The product gas has a high calorific value.
2. The small size (-4 mm) of the feed permits a short retention time and gives a better quality oil by reducing polymerization and cracking.
3. The mixing-screw that assists contacting also increases heating rates, reduces retention time, and permits retorting of fines without preventing the flow of flushing fluid and evolved hydrocarbons.
4. It allows for good temperature control.
5. The ease of operation and reliability of a process that uses commercial-size equipment available in coal processing and petroleum cracking.

The disadvantages, especially for Ontario shales, could be:

1. Yields would be only slightly higher than FA.
2. The residual carbon in the spent shale is only partially combusted, leaving a fair portion of the heating value of the mined shale.
3. The sensible heat of part of the spent shale is not recovered.
4. Thermal efficiency is about 85% for the Green River shale and would be lower on the shales of Ontario.
5. The large volume of recycled spent shales increases the overall equipment sizes, although the retort itself may be of a smaller size because of the shorter retention time.
6. As developed, the process is mechanically complex and appears to be capital intensive and difficult to operate.
7. Large quantities of shale dust are entrained by the flue gas.
8. The shale oil produced is high in particulates.
9. The size of the discharged spent shale is finer than in most processes. It could therefore weather at a faster rate and produce more dust in the environment.

Again, the Canadian Taciuk process, described below in Section 6.5.7, using the advantages of the revolving drums, may be more efficient thermally. It combusts the residual carbon of all spent shale, and appears less complex and less capital intensive. The Lurgi-Ruhrgas retort has low potential for liquid fuels production from the shales of Ontario.

6.5.4 SPHER RETORT

A little known and publicized process is the Shell Pellet Heat-Exchange Retorting **(SPHER)** process developed by the Shell Development Company for the Green River shales. The process uses a series of fluidized beds in which inert pellets are used to increase heat exchange and superficial gas velocities. The process includes three heat-exchange loops, each of which is a fluidized bed in which upward-moving shale meets a countercurrent downward flow of pellets at a different temperature. The first loop is a fast fluidized bed that preheats -1.6 mm fine, fresh shale to 300°C using the heat of a downward flow of hot 6 mm metal balls. The second loop is a dense-phase fluidized bed in which the shale is heated to retorting temperature by countercurrently moving, very hot ceramic balls. The hot spent shale is cooled in the third loop by the metal balls used in the first loop to preheat the shale.

The process development was stopped in 1976 at bench-scale retorting and cold-flow unit scale. On Green River shale, yields were at 93% of FA and thermal efficiency was said to be low at 67%. The process recovered spent shale sensible heat, but not the heating value of the residual carbon. The quality of products is unknown to us.

On Ontario shales, thermal efficiency and oil yields would be lower than that of the Green River shale and, as developed, the process is impractical.

6.5.5 BATTELLE MSFB RETORT

A more efficient alternative to the SPHER process is the Battelle Multi-Solid Fluidized Bed (MSFB) retort (Figure 6-15), an oil-shale adaptation of MSFB combustion of coals and of MSFB gasification of forest residues. The Battelle's retort is being developed under contract to the US Department of Energy and is especially designed for the retorting of the Eastern USA shales, which are similar to the shales of Ontario. Fresh shale is fed to a MSFB vessel in which the kerogen is pyrolyzed to produce gas and oil. The retorting heat is supplied by a recirculating stream of hot, combusted spent shale entrained with incoming fresh shale. The newly spent shale and the combusted shale are elutriated from the retorting vessel, captured in a cyclone, and

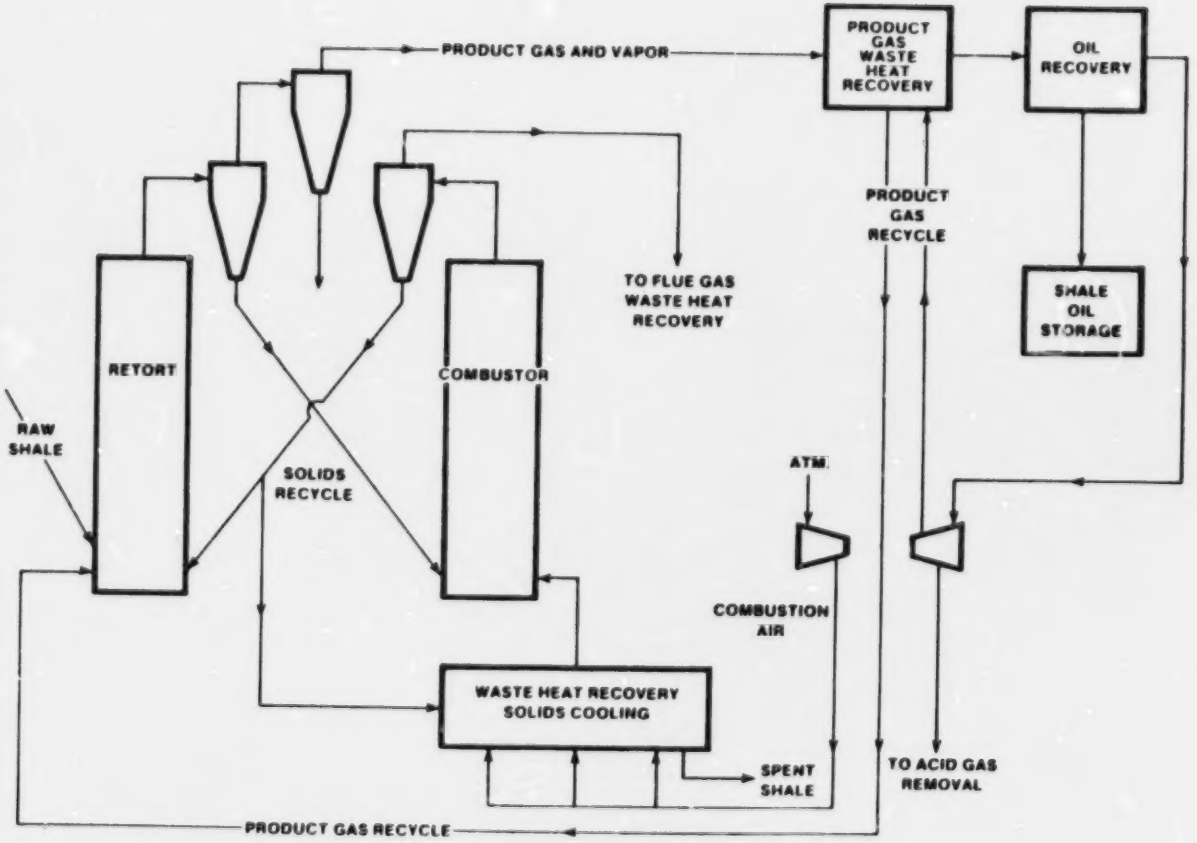

FIGURE 6-15: Battelle MSFB oil shale retort process (a Type IV retort; source: Shirley 1983).

fed to a combustor (conventional or multi-solid) in which the residual carbon is burned. Part of the combusted spent shale is returned to the retort. The rejected combusted spent shale is cooled in a three-stage, conventional, fluidized bed cooler, where the fluidizing fluid is the combustion air being reheated to 280°C. The heat of the combustion flue gas is recycled by heat exchanger. It is used together with the heat contained in product gas and vapour to generate steam for use in driving the process equipment, to provide process heat and to generate electrical power.

Tests on Kentucky shale indicate that a shale yielding 47.9 L/t (11.5 US gal/ton) should yield at least 67.2 L/t (16.1 US gal/ton) of raw shale oil containing by weight 84.5% C, 9.4% H, 1.5% N, and 3.2% S. Organic carbon conversion to raw shale oil is 46.5%. End-products with value (in 1980 US dollars) would be: light oil $0.60/US gal; high calorific value gas $3.00/MM BTU; electrical energy from steam $0.0275/kWh; and sulphur $60.00 per long ton. Using 100% equity, a 12% internal rate of return and credits for byproducts, Battelle puts production cost (in 1980 dollars) at US $31.84/bbl of upgraded shale oil (Shirley et al. 1984).

The process is in the early stages of development and advantages could be:

1. The retort accommodates a high shale throughput per square metre of vessel section.
2. Shale feed is -6 mm and fines are accepted.
3. Velocity of flushing fluid is high and this combined with 1. and 2., give very short retention time in the retort. Polymerization and cracking of the evolved hydrocarbons is prevented, resulting in higher oil and lower gas yields.
4. In some bench-scale tests, the fluidizing–flushing fluid, when high in steam content, contributed to higher oil yields.
5. Up to 95% of the residual carbon is recovered in the combustor.
6. Steam retorting tests have shown increased yields to 160% of FA.

The apparent disadvantages are:

1. Oil yields are slightly below FA in an inert atmosphere.
2. Combustion may create highly friable shale fragments that may be subjected to extreme disaggregation when recycled to the retort and high content of particulates in the retort product may end up in the shale oil that may become an unacceptable refinery feed.

3. Fluidized-bed oil yields have shown frequently to have lower H : C atomic ratio when using an inert fluidizing–flushing fluid. This is more so with finer feeds.
4. Large-scale reactors must be developed.

The Battelle MSFB retort operating in the presence of superheated steam should give much higher yields than FA and should be one of the best methods in terms of long-term economic potential for production of synthetic liquid transportation fuels.

6.5.6 PEDCO RETORT

The PEDCo, Inc. mechanically fluidized bed (MFB) retort is being developed for the Green River shale. It is based upon rotary cascade principles and allows for continuous retorting, residual carbon combustion and sensible heat recovery in a single three-compartment, rotary-kiln-like vessel. In each compartment, longitudinal lifters elevate, drop and mix the solids as the drum rotates by creating a cascading action. This action promotes contacting and assists flushing fluid circulation. The compartments are separated by gas-tight bulkheads, and the solids are transported forward between compartments by means of external spiral chutes. An internal spiral chute recycles about 80% of hot, combusted spent shale from the combustor outlet to the retort inlet. At the entrance of the retort, one volume of fresh shale is mixed with three to four volumes of hot (650°C), combusted spent shales, to bring the mixed bed to a retorting temperature of about 480°C. The evolved hydrocarbon vapours are immediately removed by a flushing fluid. The retorted shale moves to the combustion zone via a 360° spiral chute fitted with steam jets and valves to purge the vapours, and to prevent them from entering the combustion zone. The retorted shale enters the combustion zone with a co-current flow of preheated air, causing up to 95% of the residual carbon to be burned. The hot flue gas from combustion goes to a heat-recovery boiler for steam generation; the steam is used in the retorting zone and for power generation. The rejected, combusted shale proceeds to a solids cooler air preheater and is sent to disposal after cooling. Limestone may be added to the combustion zone to reduce sulphur dioxide emission.

Advantages to the PEDCo kiln-type retort are:

1. Mechanical simplicity makes it reliable, and should bring lower capital and operating costs.
2. Heat is derived from combustion of residual carbon and from sensible heat.
3. Product gas has high calorific value.
4. Heat exchange is rapid and contacting is good due to finer feed and a rotating vessel.
5. It offers wide flexibility and adaptability to feed materials.
6. It uses steam, which should help in higher oil yields, and NOx emission control.
7. It allows for ease of operation and good temperature control.
8. Large-scale kilns with good reliability records are available.
9. Kilns are air tight and acceptable environmentally.

The main disadvantages are:

1. As proposed, oil yields will be slightly higher than FA.
2. The process is at the conceptual stage of development, with only the combustion zone having been tested in batch bench-scale apparatus.

The PEDCo retort is similar to the Taciuk process (described below), but with a slightly higher potential because its concept includes the use of steam.

6.5.7 TACIUK RETORT

The Taciuk Direct Thermal Processor System (Figure 6-16), under development for the treatment of oil sands, may have application in the pyrolysis of oil shale. The Taciuk process, a Canadian technology, has been under development since 1977 by Umatac Industrial Processes Limited, with funding from the Alberta Oil Sands Technology and Research Authority.

The process uses a compartmental horizontal rotating vessel consisting of: a central core, in which oil sands are heated to temperatures of pyrolysis and produce hydrocarbon vapours; and an outer annulus, where residual carbon is burned and the

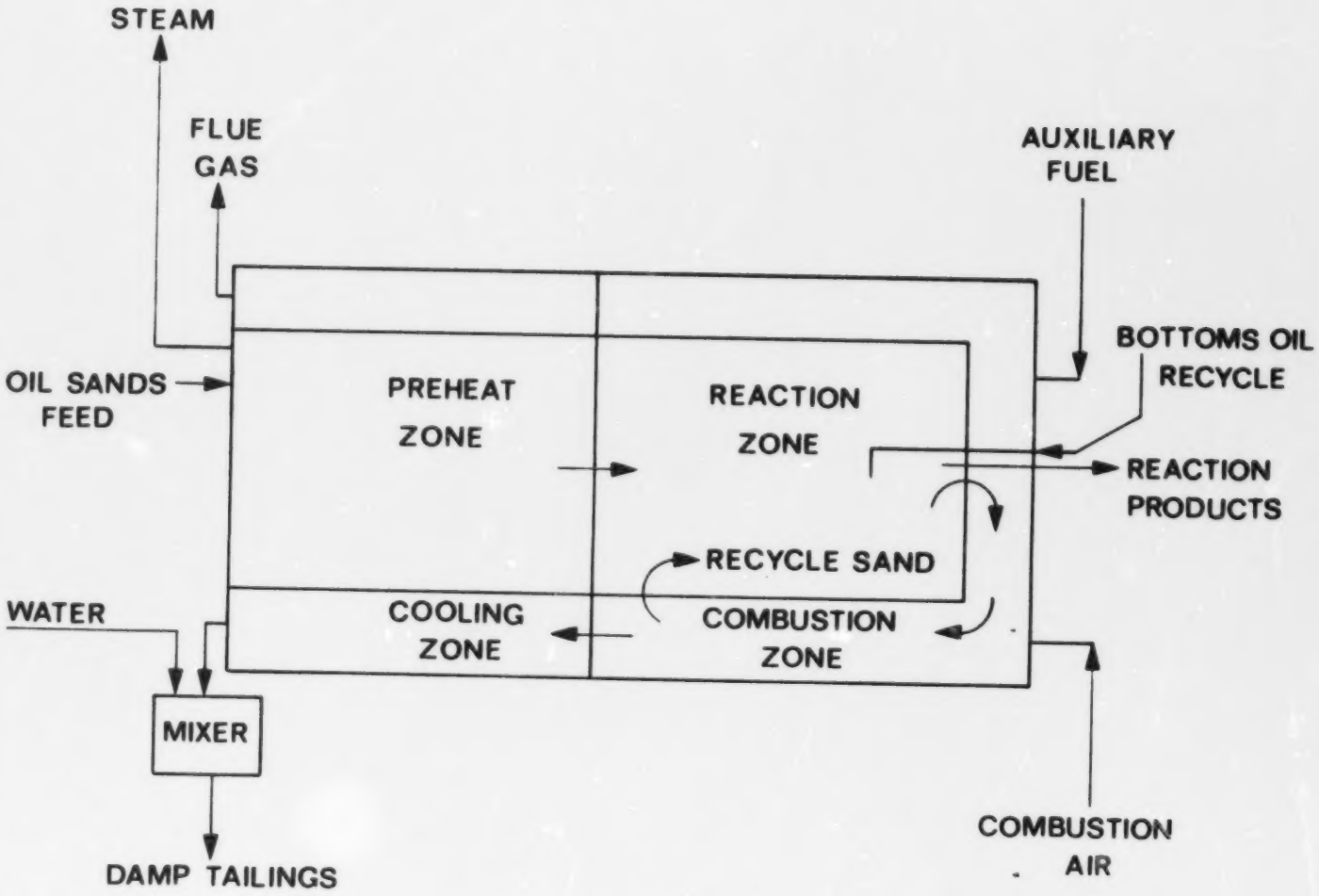

FIGURE 6-16: Taciuk direct thermal processor (a Type IV retort; source: Taciuk 1981).

combusted sand cooled. The sensible heat of the spent sand is recovered to supply retorting energy requirements.

As-mined oil sand (which could well be finely crushed and ground oil shale) is fed into the preheating section in order to heat the oil sand by heat exchange with the hot outgoing tailings sand, to evaporate connate water, and to remove oversize. The heated oil sands then move to the reaction (or retorting) zone, where they are mixed with hot combusted sand. The resulting temperature is adequate to thermally crack (or pyrolyse) the hydrocarbons, yield condensable and non-condensable hydrocarbon vapours, and leave a coke-residue coating on the spent sand. The vapours are passed through a cyclone to remove fine solids and proceed through a fractionating tower, where liquid fractions may be separated for further processing. Off-gases are cooled to condense light ends and water, and sent to a gas processing plant.

The coke-coated sand is discharged into the combustion zone, where injected preheated air burns the residual carbon to provide most of the process heat. Auxiliary burners are required for start-up, trim control and for emergency. The hot combusted sand passes through a recycling arrangement that ensures an adequate heat supply to the reaction zone, while allowing it to move into an outer heat exchange zone. Here, together with combustion gases, it will be cooled via heat exchange by the incoming fresh oil sand. The partially cooled sand is removed from the vessel, dampened by the addition of water and transported to a disposal site. Combustion gases are removed from the vessel, passed through cyclones to reduce the fine solids, then passed through chemical wet scrubbers to remove most of the remaining solids and sulphur dioxide. The liquid from the wet scrubber is used for cooling the tailings sand (Taciuk 1981).

In pilot-plant testing of oil sands, it has been shown that the vessel is energy self-sufficient, with 80% of the heat requirement coming from combustion of the coke and the remainder from sensible heat recovery. A 5 tonne/hour pilot-plant, 2.7 m in diameter, 8 m long and rotating at 4.5 rpm has been in operation in Calgary since 1978, and has processed 8,000 tonnes of mainly Canadian oil sands. Since 1977, some $5.5 million was spent on developing the process from concept to pilot-plant construction, with performance testing and with steady operational runs of up to 100 hours. Umatac's next step is the construction of a 90 tonne/hour demonstration plant, which

will operate for two years and will be sited near an operating oil sand mine with available utilities. The demonstration, scheduled to be completed in 55 months, is expected to cost $74.3 million for engineering, procurement, construction, and operation.

The process tested Colorado and Brazilian oil shales. Results are not available.

Advantages of the Taciuk process, could be:

1. Heat is derived from internal combustion of the residual carbon in the spent shale and from the sensible heat of the retort products.
2. High calorific value off-gas is produced.
3. It offers wide flexibility and adaptability to feed materials other than oil sands such as oil shales, coal and lignite.
4. Heat exchange is rapid and contacting is good because of fine feed and a rotating vessel.
5. It does not require the removal of the fines to permit gas flow and heat transfer.
6. It allows for good temperature control.
7. It provides for ease of operation, with start-up or shut-down not requiring emptying of the vessel.
8. Large-scale rotating vessels exist and have operated in worse heating–cooling conditions (iron and cement industry) than could be expected from the retorting and combusting of oil shale.
9. The vessel is air tight and acceptable environmentally.

The main disadvantages could be:

1. Oil yields would at best equal FA for Ontario shales unless the process can be adapted to retorting in the presence of superheated steam, at or slightly above atmospheric pressure, or in the presence of hydrogen at high pressure.
2. The use of parallel-flow of solids and gases makes the system thermally less efficient than countercurrent flow.

CANMET should investigate the possibility of retorting Ontario shales in a modified Taciuk Thermal Processor to react the fresh shale with the steam of the preheat zone, or to react the residual carbon of the spent shale with superheated steam prior to combustion. If such a modification could be made, it is possible that the Canadian

process could be made to yield from 140% to more than 160% of FA and may be a viable alternative to a hydrogen retorting process (Section 6.4.6). Such a modified version could have a potential for the production of liquid transportation fuels from Ontario shales.

6.6 SURFACE RETORTING WITH SUPERHEATED STEAM

Retorting in the presence of superheated steam is an old oil shale application. It was abandoned in the first quarter of the 20th century with the collapse of the oil shale industry as it existed then. The method is making a comeback with the need to retort organic-rich shales containing kerogen with a low H : C atomic ratio, such as the Eastern USA and Ontario oil shales. Southern Ontario has abundant waste heat and steam at Ontario Hydro generating plants, and abundant capacity for the production of superheated steam at the Bruce, Darlington and Pickering atomic energy centres.

The Scottish oil-shale industry, starting circa 1880, used steam injection (with air) in a gas-making chamber to produce the flushing fluid for the hydrocarbons evolved in the retorting zones. It has been said that the use of steam resulted in increased oil and gas yields, and permitted the recovery of large quantities of ammonia. We have not located any written information on the achieved gain. The flushing fluid was produced in a gas-making chamber by reacting the residual carbon (or coke) in the spent shale with steam and air at 700°C to give carbon dioxide, carbon monoxide, and probably lesser amounts of hydrogen gas.

The performance of the Pumpherston retort on Green River shale was investigated by the USBM in the 1920s. Air-free water injection at the base and atmospheric pressure were used, and two runs showed increase in oil and gas yields, with both being of higher quality. The hydrogen content of the off-gas increased from 15 to 44 m^3/t with a comparable decrease in carbon monoxide content and a 6% increase in oil yields from 88.0% to 93.3% of FA. The yields increased to the point where quenching of the spent shale occurred (Gavin and Desmond 1930). Since only water was injected, the beneficial results appeared to be related to increased flushing velocity created by the steam, which reduced cracking of the evolved hydrocarbons in the retorting zone.

Hydrogen production appears to result from reaction with the spent shale, not from cracking in the retorting zone.

In the early 1950s, the USBM conducted two experimental runs using Green River shale in a Royster retort (Type III), the recycled off-gases being replaced by superheated steam at atmospheric pressure. The off-gases showed an increase in hydrogen-gas content from 15 to 64 m^3/t and a comparable decrease in carbon monoxide (Wells and Ruark 1952). In these experiments, steam was used as a heat carrier and flushing fluid, and greatly reduced the intensity of carbon monoxide-producing reactions, such as cracking.

Again, on Green River shales, Marathon Oil Company experimented with steam retorting in thermogravimetric analysis and bench-scale apparatus. Allred (1981) reported that superheated steam:

1. Increased oil and gas yields respectively up to 115% and up to 200% of FA.
2. Permitted retorting at lower temperature, 470°C versus 500°C, and prevented carbonate decomposition, an endothermic reaction that reduces the quality of the off-gas by producing carbon dioxide.

In addition:

3. High steam-sweep velocity increased oil yields, but too high a velocity decreased the quality of the oil.
4. Product gases doubled, and contained more hydrogen gas and less carbon monoxide.
5. Sufficient hydrogen gas could be produced for the gases to be useful for the hydrogenation of shale oil.
6. Shale oil and steam condensed in an immiscible phase and were easier to separate.
7. Non-condensable off-gases did not have to be recycled.
8. The pH of the retorted calcareous shale was almost neutral.

For Allred (1981), the main disadvantage is that the required heat of vaporization is very high for steam. This heat of vaporization must be removed to achieve

condensation of the evolved condensable hydrocarbons and must be recovered to vaporize the recycled steam.

Retorting of Eastern oil shale with steam was tested by Battelle in the development of their MSFB retort. It was found that oil yields of up to 162% of FA were achieved when the fluidizing fluid contained in excess of 38% steam, compared to retorting in a nitrogen atmosphere (Shirley et al. 1984). No indication is given of the temperature of the incoming steam or retorting bed, or of the fluidized bed pressure that is probably near atmospheric pressure, based on the commercial concept.

The shales of Ontario are similar to those of the Eastern USA, and should be tested for retorting with superheated steam at atmospheric pressure or under increased pressure. The availability of excess steam and/or waste heat at the energy centres should greatly reduce the cost of vaporizing water and heating the steam to 500–700°C. The cost benefit might be offset to some degree by the costs of transporting raw shale to the energy centre and spent shale back to the mine for disposal. The off-gas could contain hydrogen gas which is useful for the hydrogenation of shale oil. Also, as in the case of the Scottish shale, the off-gas could contain condensable ammonia. The environmental impact of an oil shale industry could, therefore, be reduced as analytical results from the Canada Department of Mines, pre-1930, indicated that 4–5 kg of ammomium sulphate could be produced per tonne of Ontario shales.

6.7 PROCESS SELECTION PARAMETERS

All retorts are developed for a particular oil shale and for a suite of definite, marketable end-products. Thus, the selection of a retorting process must take into consideration hundreds of physical and chemical parameters that must be evaluated relative to the following factors:

(1) specifications of the oil shale feed;
(2) kerogen conversion to liquid and gas yields, and amounts of residual carbon left in spent shale;
(3) effects of process conditions;
(4) thermal efficiency;

(5) external energy and consumable requirements;
(6) retort design and operability;
(7) processing requirements for obtaining marketable products;
(8) processing requirements of waste products (spent shale, water, flue gas, etc.); and
(9) capital and operating costs, etc.

Little is known about the shales of Ontario, but sufficient information is available to provide the basis for an educated guess as to the more suitable process(es) for treating these shales.

The organic matter or kerogen of the Ontario oil shales is deficient in hydrogen, has much lower hydrogen-to-carbon atomic ratio, and yields less oil and more gas under inert atmosphere pyrolysis than the higher yielding shales of Western USA, Brazil and Australia. The shales of Ontario, like the shales of the Eastern USA, may have organic carbon contents similar to their high oil yielding counterparts. However, the quantity and quality of their organic matter is such that organic carbon conversion to oil and gas yields is low, and considerable amounts of organic carbon are left as residual carbon in spent shale.

6.8 CONCLUSIONS

Oil-shale development in the Eastern USA and preliminary characterization studies of the oil shales of Ontario indicate that it should be technically feasible to recover more than 100 L/t (24 US gal/t) of raw or upgraded shale oil or synthetic crude oil from Ontario shales by retorting or solvent extraction. It should also be possible to blend the synthetic liquid product with conventional crude oil for conventional refining to produce liquid transportation fuels. In some cases, the product could be directly upgraded to refinery feedstock.

Based on the content of this chapter, the processes most suitable for the production of liquid transportation fuels would:

(1) give higher oil yields than the generally accepted standard FA;

(2) have a high organic conversion to hydrocarbon vapours;

(3) utilize the residual carbon of the spent shale; and

(4) have a high thermal efficiency.

In order of decreasing priority, the following processes should be investigated for the shales of Ontario:

1. Hydrogen-retorting processes, such as HYTORT: these should produce in excess of 100 L/t (24 US gal/ton) of upgraded shale oil or synthetic crude oil with some gas, and substantial amounts of ammonia and sulphur.
2. Superheated steam retorting in modified Taciuk, Circular-Grate or Near-Surface retorts: these retorts appear to have low capital and operating costs, and seem less complex mechanically than 1.
3. Flash Hydropyrolysis, as developed by the Rockwell International Corporation: this technology should give better organic conversion to oil than 2., but the process is technically complex and little is known about the quality of the end-products.
4. Fluidized-bed retorting, with superheated steam as in the Battelle's MSFB retort: next to 3, in terms of conversion to oil, but like 3., is technically complex and the quality of the end-products is uncertain.
5. Thermal Solution, with superheated steam or with hydrogen-donor solvents: thermal solution should give higher carbon conversion to oil than 3. and 4.; but the difficulties in finding low cost, effective solid–liquid separation techniques lowers its potential.

7. ECONOMIC ANALYSIS

7.1 INTRODUCTION

The project and schedule, outlined below, was developed for the purpose of analyzing oil shale economics and is considered reasonable. The reader is advised, however, that all assumptions are based upon limited data and that engineering cost estimates have **not** been undertaken. Comments on technology and processes are based on available literature, supported by the limited analytical work done by the OGS and are generally based on projects elsewhere.

The costs projected are for an oil shale project located in southern Ontario. They include exploration, construction and operation of a pilot plant, development and operation of a mine, and a 30,000-ton/d retorting complex. Two process alternatives have been examined: Paraho and HYTORT. This comparison could be based on one of several parameters, such as synthetic crude oil output for instance. However, this would tend to mask several important differences between the two processes. It was decided therefore that the comparison would be based on a plant capacity, for both processes, of 30,000 ton/d of feed to the retort.

Capital and operating costs, developed for exploration and mining, were prepared by WGM, drawing upon its own experience and upon capital and operating cost data for existing mines of similar size and complexity. Capital and operating costs for retorting were derived from those in papers presented at various symposia on Eastern USA oil shales. These were modified by WGM to reflect various assumptions made, to reflect the location in southern Ontario and to reflect specific characteristics of the Kettle Point Formation.

Without site-specific parameters regarding the depth and shape of the deposit(s), the nature of the rocks, and their milling characteristics, the accuracy of the costs presented can be considered order-of-magnitude only.

There is no doubt that production of liquid and gaseous hydrocarbons from Ontario oil shales is technically feasible. However, as with many capital-intensive hydrocarbon projects, the development of Ontario's oil shales will be governed by the demand for hydrocarbon energy, prices, and the fiscal regime established by the Federal and Provincial governments. Nonetheless, the oil shales of Ontario represent an enormous domestic hydrocarbon resource. New process technology under development may allow more complete conversion of the contained organic carbon, which could result in yields of gaseous and liquid products nearly equivalent to the more fully investigated Western USA shales.

Ontario and other eastern North American oil shales have a number of economic factors in their favour. These include:

Transportation

Ontario shales occur near Canada's largest hydrocarbon consumption centres. Costs of transporting products would be far lower than from developments, such as the Athabasca oil sands, western coal-based sythentic-fuel plants, or even the Beaufort Sea. Similarly, Ontario oil shale products enjoy transportation advantages relative to other oil shale deposits of current interest, such as those in western United States or in Australia.

Infrastructure

With the exception of the James Bay Lowlands area, Ontario's oil shales occur in areas where skilled labour, power, housing, and manufacturing are all available. Large infrastructure costs are required to develop Western USA shales.

Water

The availability of process water is a major economic and environmental concern in an operation of this size. Many of the world's oil shales are located in relatively arid areas — Morocco, Australia, and Colorado, for example. Ontario, however, has an abundant supply of water.

Power

Power, heat, and possibly hydrogen are major requirements for a successful oil shale industry in eastern North America. Ontario has the ability to make available unused waste heat and hydrogen from its nuclear power plants, and a plentiful supply of inexpensive natural gas.

7.2 PROJECT OUTLINE AND ASSUMPTIONS

Because of their yield and thickness, the oil shales of the Kettle Point Formation have been selected as the subject of this study. These oil shales are relatively thin and flat-lying, and are covered by some 45 m of overburden. For this reason, it is not believed that either the in-situ or modified in-situ process routes will be applicable. Furthermore, since the province has an abundant supply of electrical power, the combustion and co-combustion routes are contra-indicated.

It seems likely that the Kettle Point Formation oil shales would therefore be exploited by either the conventional or beneficiation routes. While in theory the beneficiation route appears to present the most attractive option, it is impossible at this time to determine a plant design for retorting a kerogen concentrate. It is assumed for the purposes of this study that these oil shales would be exploited by the conventional route.

Two scenarios have therefore been developed to illustrate a practical approach to oil shale development. Both are based on an open-cast mine near Sarnia, Ontario to produce oil shale from the Kettle Point Formation. This site is blessed with a satisfactory supply of water and all necessary infrastructure.

It has been assumed that the process plant would be based on either the Paraho or the HYTORT process design, and that 30,000 ton/d would be retorted. Since screening is necessary to prepare run-of-mine shale for retorting, with the consequent loss of the fine fraction, the mining rate must be greater: 33,600 ton/d for the Paraho plant and 37,500 ton/d for the HYTORT plant. The assumed fine fraction to be discarded (11% of material mined in the case of Paraho and 20% for HYTORT) is higher than reported in some sources. For instance, 9% for Paraho and 15% for HYTORT is quoted by Parkinson et al. Thus, this assumption is felt to be quite cautious. Other process parameters will be as follows:

	PARAHO	HYTORT
Mining Rate (ton/d).....	33,600	37,500
Fischer Assay (US gal/ton).....	9.5	9.5
Process Yield (US gal/ton).....	11.3	19.6

Annual Production	PARAHO	HYTORT
Upgraded shale oil (bbl)	2,015,310	4,620,000
Light oil (bbl)	654,060	—
High BTU gas (MM BTU)	5,957,160	—
Electrical energy (MWh)	329,472	—
Sulphur (long tons)	37,950	245,000
Ammonia (short tons)	—	41,500

The output from the Paraho process includes upgraded shale oil and light oil (BTX) consisting of benzine, toluene and xylene. Together these outputs are assumed to be 11.3 US gal/ton. In addition, there will be a significant output of high calorific value gas and excess electricity, as well as a modest amount of sulphur.

Output from the HYTORT process will include upgraded shale oil, a greater proportion of contained sulphur and ammonia.

7.3 DISCUSSION

Traditional open-cast mining techniques are specified as described in Chapter 4 and costs have been adjusted to reflect the larger tonnages mentioned above.

The HYTORT and the Paraho CH processes have been selected for two reasons. Detailed economic studies have already been completed for each of these processes on plant designs specifically developed for Eastern USA oil shales. These economic studies can therefore be readily adapted to prepare a model for the oil shales of Ontario. The second reason is that they provide an example of two very different types of processes. In the case of HYTORT, process yields are significantly increased by retorting in the presence of hydrogen under pressure. These advantages could however be offset by higher capital and operating costs inherent in this design. In the case of Paraho, these costs are lower, but the eventual process yields and the product quality are also lower.

For the purpose of this study, we have assumed that the HYTORT process would produce the maximum amount of oil. The process design can be adapted to produce

varying ratios of oil to gas. In an area where natural gas is expensive or not readily available, increased amounts of gas would be produced for recycling to the process. This is not the case in Ontario and we have therefore optimized the oil yield from the process.

All capital and operating costs for both processes have been modified from similar studies conducted upon Eastern USA oil shales. Paraho process economics were originally studied by Davy McKee (Vyas et al. 1981) and HYTORT process economic studies were performed by Bechtel (Rex et al. 1983, HYCRUDE 1984).

In addition to shale oil, byproducts from the HYTORT process are reported to be elemental sulphur and ammonia. Davy McKee reports that light oil, high-BTU gas and sulphur are byproducts of the Paraho process. In practice, both processes will produce a certain fraction of light oil and high-BTU gas and, in fact, the overall quality of the HYTORT product is better than that from the Paraho process. This factor is reflected in the anticipated revenues applied to process products and byproducts in the WGM study.

7.4 DEVELOPMENT PROGRAM

Prior to the development of an oil shale complex, a deposit of economic grade will be found and acquired; reserves, developed; and mining methods determined. Parallel with these investigations, extensive and continuing research will be undertaken to develop the processing technology.

Some of the technology previously outlined is undeveloped. Consequently, a full-scale pilot-plant operation almost certainly would be required in order to confirm the process parameters.

The following outline describes a phased program for development of one site large enough to support a mine to feed 30,000 ton/d to the retorts. Since fines are screened out before retorting, the mine must be large enough to produce 37,510 ton/d (in the HYTORT case) or 33,600 ton/d (for the Paraho process).

PHASE 1 – TARGET EVALUATION

Regional geological and geochemical surveys and compilation.

Sample analyses.

Laboratory- and bench-scale process testing.

Selection of most favourable site.

Drilling to establish tonnage, grade and shape of the deposit, with a minimum in-situ reserve of 300 million tons. Assuming an average oil shale thickness of 10 m, this will require drilling of an area 3,300 m by 3,300 m.

Initiation of small-scale pilot-plant testing, utilizing core samples.

Preliminary feasibility studies on mine and process plant.

Gathering of environmental and socio-economic baseline data.

PHASE 2 – TARGET DEVELOPMENT

Establish and operate a small mine to produce oil shale for the pilot plant.

Establish and operate a pilot plant.

Establish optimum treatment conditions for the shale oil recovered from the pilot retorting operation.

Complete detailed feasibility studies so that a production decision can be made and financing arranged.

PHASE 3 – CONSTRUCTION

Design, develop and construct a 35,000 ton/d mine, a 30,000 ton/d retorting plant, and a shale oil upgrading complex.

7.5 CAPITAL AND OPERATING COSTS

Processing costs have been derived from several published sources (Hilleke and Hanna 1981, Vyas et al. 1981, and HYCRUDE 1984). The costs for mining have been developed by WGM, based on costs from similar mines. These costs are summarized in Tables 7-1 and 7-2 and are given in mid-1982 US dollars. No attempt has been made to update these figures. Capital costs for the HYTORT complex are subdivided into direct process plant requirements (mining, crushing, retorting, and byproduct recovery) and off-site costs (such as hydrogen production, shale oil storage, spent shale disposal, oxygen plant, utilities, and professional services).

TABLE 7-1

CAPITAL COST SUMMARY

(millions US dollars, mid-1982)

DESCRIPTION	PARAHO	HYTORT
Mining	95	102
Process Plant	466	422
Off-sites, etc.	–	296
	561	820

TABLE 7-2

OPERATING COST SUMMARY

(millions US dollars, mid-1982)

DESCRIPTION	PARAHO	HYTORT
Mining	12,975	14,480
Processing	50,125	91,900
	63,100	106,380

7.6 ANNUAL REVENUE

In the case of the HYTORT plant, revenue will be derived from the sale of shale oil, sulphur and ammonia. In all the cashflow projections, we have used a world oil reference price to which all other product prices are related. This world oil reference price is $29/bbl in the base case. On this basis, we have assumed that the shale oil will be sold at a price of $26/bbl. Sulphur will be sold at $120/long ton, and ammonia at $150/ton.

In the case of the Paraho plant, production of hydrocarbons will consist of shale oil, light oil and high-BTU gas. With a world oil reference price of $29/bbl, the shale oil would be priced at $25/bbl, the light oil at $28.00, and $2.92/MM BTU for the gas.

The base prices for HYTORT upgraded shale oil ($26/bbl) and Paraho shale oil ($25/bbl) are arbitrarily selected to take into account assumed product quality.

The Paraho process also produces saleable electrical energy and sulphur which, for the base case, we have priced at 2.19¢/kWh and $120/long ton.

7.7 FINANCIAL PROJECTIONS

In order to compare the economics of the two processes and to illustrate possible project returns, a financial model was constructed. The costs used in the model for the base case for each process are as outlined above in Tables 7-1 and 7-2. A five-year preproduction period was used, which could well be too short in practise. A 20-year production period was projected.

All costs are shown in constant US dollars, based on 1982 price levels. Taxes were calculated on the basis of Ontario and Canadian tax levels in June 1985, with no special incentives. Financing is assumed to be 100% equity, with no interest charged.

Having established a base case for each process, several alternatives were developed and these are summarized in Table 7-3.

The model was asked to calculate the product prices necessary to achieve certain rates of return, all else being equal. The resulting product prices bear the same pro rata relationship to the world reference price as in the base case (i.e. the Paraho light oil price will always be 28/29 of the world reference price).

Rates of return of 11% and 15% were used as benchmarks. The real interest rate on long-term securities, such as government or high-grade corporate bonds, is relatively stable, with a range of approximately 1% above and below the long-term average of

TABLE 7-3

COMPARISON OF HYTORT AND PARAHO PROCESS VARIABLES WITH RETURN ON INVESTMENT

CASE	HYTORT			PARAHO		
	World Reference Price (US $/bbl)	Payback Years	ROI (%)	World Reference Price (US $/bbl)	Payback Years	ROI (%)
Equity: 100%						
Base	29.00	16	1.3	29.00	16	1.5
11% ROR	36.87	6	11.0	38.89	6	11.0
15% ROR	40.63	4	15.0	43.71	4	15.0
Metal Revenue	29.00	12	3.4	29.00	12	3.5
Metal Revenue - 11% ROR	34.97	6	11.0	36.61	6	11.0
Equity: 25%						
11% ROR	44.80	8	11.0	50.09	7	11.0
15% ROR	49.54	6	15.0	56.40	5	15.0

3%, after tax. The average 'real' interest component of the discount rate may, therefore, be taken as 3% over the long-term. A risk element must then be added to the 'real' interest rate. We have added 8% (in the case of an 11% ROR) and 12% (15% ROR). All costs, prices and projections are expressed in constant dollars with no inflation. Thus, no inflation element is required.

The same question was then asked for alternatives with financing assumed to be 75% debt, with interest calculated at a rate of 7%. This rate includes 'pure' interest plus project risk premium, but no premium for inflation, since the projections are all based on constant dollars.

Finally, an arbitrary increase equal to 10% of calculated revenue was added to total revenue, to allow for possible sales of contained metals. The theoretical value of contained metals is far higher than this, but several problems must be faced including the technical and economic feasibility of metals recovery, the marketability of large quantities of several rare metals, and the capital and operating costs. Nevertheless, some recovery is possible and an attempt has been made to show the effect.

Cashflow projections for the base case for both processes are shown on Tables 7-4 and 7-5.

7.8 FINANCIAL ANALYSIS

In all cases studied, the Paraho process is less attractive financially than the HYTORT process. This result is shown even though the estimated Paraho costs are 31% less than the HYTORT process (in the case of capital costs) and 41% less (in the case of operating costs). The reason for this, of course, is that projected yields from the HYTORT process result in annual revenues which are 59% greater than the Paraho process. This difference in revenue more than offsets the higher costs of the HYTORT process. The higher costs, in turn, are the result generally of the much greater oil yield to be expected from the HYTORT process. This comparison is valid for all the cases studied. Higher oil prices are required for the Paraho process to produce

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	19
Production Statistics												
Daily Retorting Rate - Tons per Day	-	-	-	-	-	30,000	30,000	30,000	30,000	30,000	30,000	30,0
Oil Recovery - Bbls per ton	-	-	-	-	-	.4667	.4667	.4667	.4667	.4667	.4667	.46
Oil Produced per year(MBbls)	-	-	-	-	-	4,620	4,620	4,620	4,620	4,620	4,620	4,62
Light Oil (MBbls)	-	-	-	-	-	-	-	-	-	-	-	
High BTU Gas (MMBtu)	-	-	-	-	-	-	-	-	-	-	-	
Electrical Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	
Sulphur (M Long Tons)	-	-	-	-	-	245	245	245	245	245	245	2
Ammonia (M Short Tons)	-	-	-	-	-	42	42	42	42	42	42	
PRICES												
World Oil Reference Price ($/Bbl)	-	-	-	-	-	29.00	29.00	29.00	29.00	29.00	29.00	2
Shale Oil Price ($/Bbl)	-	-	-	-	-	26.00	26.00	26.00	26.00	26.00	26.00	26
Light Oil Price ($/Bbl)	-	-	-	-	-	28.00	28.00	28.00	28.00	28.00	28.00	28
High BTU Gas ($/MMBtu)	-	-	-	-	-	2.92	2.92	2.92	2.92	2.92	2.92	2.
Electrical Energy (Cents per KWh)	-	-	-	-	-	2.19	2.19	2.19	2.19	2.19	2.19	2.
Sulphur ($/Long Ton)	-	-	-	-	-	120.00	120.00	120.00	120.00	120.00	120.00	120.
Ammonia ($/Short Ton)	-	-	-	-	-	150.00	150.00	150.00	150.00	150.00	150.00	150.
REVENUE												
Shale Oil	-	-	-	-	-	120,120	120,120	120,120	120,120	120,120	120,120	120,1
Light Oil	-	-	-	-	-	-	-	-	-	-	-	
High Gas	-	-	-	-	-	-	-	-	-	-	-	
Electrical Energy	-	-	-	-	-	-	-	-	-	-	-	
Sulphur	-	-	-	-	-	29,400	29,400	29,400	29,400	29,400	29,400	29,4
Ammonia	-	-	-	-	-	6,225	6,225	6,225	6,225	6,225	6,225	6,2
Contained Metals	-	-	-	-	-	-	-	-	-	-	-	
Total Revenue	-	-	-	-	-	155,745	155,745	155,745	155,745	155,745	155,745	155,7
Operating Costs												
Mining Costs	-	-	-	-	-	14,480	14,480	14,480	14,480	14,480	14,480	14,4
Processing Costs	-	-	-	-	-	91,900	91,900	91,900	91,900	91,900	91,900	91,9
Interest Expense	-	-	-	-	-	-	-	-	-	-	-	
Total Operating Costs	-	-	-	-	-	106,380	106,380	106,380	106,380	106,380	106,380	106,3
Operating Profit	-	-	-	-	-	49,365	49,365	49,365	49,365	49,365	49,365	49,3
						CASH FLOW						
Operating Profit	-	-	-	-	-	49,365	49,365	49,365	49,365	49,365	49,365	49,3
Plus: Bank Loan	-	-	-	-	-	-	-	-	-	-	-	
Less: Capital Investment	1,500	10,500	204,500	402,458	199,962	1,100	-	-	-	-	-	
Repay Bank Loan	-	-	-	-	-	-	-	-	-	-	-	
Federal Taxes	-	-	-	-	-	-	-	-	-	-	-	
Ontario Provincial Taxes	-	-	-	-	-	-	-	-	-	-	-	
Cash Flow	(1,500)	(10,500)	(204,500)	(402,458)	(199,962)	48,265	49,365	49,365	49,365	49,365	49,365	49,3
Accumulated Cash Flow	(1,500)	(12,000)	(216,500)	(618,958)	(818,920)	(770,655)	(721,290)	(671,925)	(622,560)	(573,195)	(523,830)	(474,4
Rate of Return (%)	-	-	-	-	-	-	-	-	-	-	-	
Present Value at 10%	(1,430)	(10,531)	(171,674)	(459,976)	(590,197)	(561,622)	(535,054)	(510,901)	(488,941)	(468,982)	(450,835)	(434,3
Present Value at 15%	(1,399)	(9,913)	(154,107)	(400,869)	(507,481)	(485,105)	(465,203)	(447,898)	(432,450)	(419,764)	(408,366)	(398,4

TABLE 7-4

CASHFLOW PROJECTION
HYTORT Process - Base Case
('000 US DOLLARS)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	-
.4667	.4667	.4667	.4667	.4667	.4667	.4667	.4667	.4667	.4667	.4667	.4667	.4667	.4667	.4667	.4667	-
4,620	4,620	4,620	4,620	4,620	4,620	4,620	4,620	4,620	4,620	4,620	4,620	4,620	4,620	4,620	4,620	92,400
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
245	245	245	245	245	245	245	245	245	245	245	245	245	245	245	245	4,900
42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	330
29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00
26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00
28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00
2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92
2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19
120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00
150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00
120,120	120,120	120,120	120,120	120,120	120,120	120,120	120,120	120,120	120,120	120,120	120,120	120,120	120,120	120,120	120,120	2,402,400
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29,400	29,400	29,400	29,400	29,400	29,400	29,400	29,400	29,400	29,400	29,400	29,400	29,400	29,400	29,400	29,400	588,000
6,225	6,225	6,225	6,225	6,225	6,225	6,225	6,225	6,225	6,225	6,225	6,225	6,225	6,225	6,225	6,225	124,500
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
155,745	155,745	155,745	155,745	155,745	155,745	155,745	155,745	155,745	155,745	155,745	155,745	155,745	155,745	155,745	155,745	3,114,898
14,480	14,480	14,480	14,480	14,480	14,480	14,480	14,480	14,480	14,480	14,480	14,480	14,480	14,480	14,480	14,480	289,600
91,900	91,900	91,900	91,900	91,900	91,900	91,900	91,900	91,900	91,900	91,900	91,900	91,900	91,900	91,900	91,900	1,837,999
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
106,380	106,380	106,380	106,380	106,380	106,380	106,380	106,380	106,380	106,380	106,380	106,380	106,380	106,380	106,380	106,380	2,127,600
49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	987,300
									CASH FLOW							
49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	987,300
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	820,020
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	1,798	9,996	9,996	9,996	31,787
-	-	-	-	-	-	-	-	-	-	-	-	1,663	4,278	4,278	4,278	14,498
49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	49,365	45,904	35,090	35,090	35,090	120,995
73,195)	(523,830)	(474,465)	(425,100)	(375,735)	(326,370)	(277,005)	(227,640)	(178,275)	(128,910)	(79,545)	(30,180)	15,724	50,815	85,905	120,995	120,995
-	-	-	-	-	-	-	-	-	-	-	-	.19	.58	.94	1.26	1.26
68,982)	(450,835)	(434,138)	(419,341)	(405,707)	(393,313)	(382,045)	(371,802)	(362,490)	(354,024)	(346,329)	(339,332)	(333,418)	(329,308)	(325,571)	(322,174)	(322,174)
19,764)	(408,286)	(398,491)	(389,687)	(382,406)	(375,900)	(370,243)	(365,323)	(361,046)	(357,326)	(354,091)	(351,279)	(349,004)	(347,493)	(346,178)	(345,035)	(345,035)

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Production Statistics											
Daily Retorting Rate - Tons per Day	-	-	-	-	-	30,000	30,000	30,000	30,000	30,000	30,000
Oil Recovery - Bbls per ton	-	-	-	-	-	.2036	.2036	.2036	.2036	.2036	.2036
Oil Produced per year(MBbls)	-	-	-	-	-	2,015	2,015	2,015	2,015	2,015	2,015
Light Oil (MBbls)	-	-	-	-	-	654	654	654	654	654	654
High BTU Gas (MMBtu)	-	-	-	-	-	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161
Electrical Energy (MWh)	-	-	-	-	-	329,472	329,472	329,472	329,472	329,472	329,472
Sulphur (M Long Tons)	-	-	-	-	-	38	38	38	38	38	38
Ammonia (M Short Tons)	-	-	-	-	-	-	-	-	-	-	-
PRICES											
World Oil Reference Price ($/Bbl)	-	-	-	-	-	29.00	29.00	29.00	29.00	29.00	29.00
Shale Oil Price ($/Bbl)	-	-	-	-	-	25.00	25.00	25.00	25.00	25.00	25.00
Light Oil Price ($/Bbl)	-	-	-	-	-	28.00	28.00	28.00	28.00	28.00	28.00
High BTU Gas ($/MMBtu)	-	-	-	-	-	2.92	2.92	2.92	2.92	2.92	2.92
Electrical Energy (Cents per KWh)	-	-	-	-	-	2.19	2.19	2.19	2.19	2.19	2.19
Sulphur ($/Long Ton)	-	-	-	-	-	120.00	120.00	120.00	120.00	120.00	120.00
Ammonia ($/Short Ton)	-	-	-	-	-	110.00	110.00	110.00	110.00	110.00	110.00
REVENUE											
Shale Oil	-	-	-	-	-	50,383	50,383	50,383	50,383	50,383	50,383
Light Oil	-	-	-	-	-	18,314	18,314	18,314	18,314	18,314	18,314
High Gas	-	-	-	-	-	17,395	17,395	17,395	17,395	17,395	17,395
Electrical Energy	-	-	-	-	-	7,215	7,215	7,215	7,215	7,215	7,215
Sulphur	-	-	-	-	-	4,554	4,554	4,554	4,554	4,554	4,554
Ammonia	-	-	-	-	-	-	-	-	-	-	-
Contained Metals	-	-	-	-	-	-	-	-	-	-	-
Total Revenue	-	-	-	-	-	97,861	97,861	97,861	97,861	97,861	97,861
Operating Costs											
Mining Costs	-	-	-	-	-	12,975	12,975	12,975	12,975	12,975	12,975
Processing Costs	-	-	-	-	-	50,125	50,125	50,125	50,125	50,125	50,125
Interest Expense	-	-	-	-	-	-	-	-	-	-	-
Total Operating Costs	-	-	-	-	-	63,100	63,100	63,100	63,100	63,100	63,100
Operating Profit	-	-	-	-	-	34,761	34,761	34,761	34,761	34,761	34,761
						CASH FLOW					
Operating Profit	-	-	-	-	-	34,761	34,761	34,761	34,761	34,761	34,761
Plus: Bank Loan	-	-	-	-	-	-	-	-	-	-	-
Less: Capital Investment	1,500	10,500	139,750	272,958	135,212	1,100	-	-	-	-	-
Repay Bank Loan	-	-	-	-	-	-	-	-	-	-	-
Federal Taxes	-	-	-	-	-	-	-	-	-	-	-
Ontario Provincial Taxes	-	-	-	-	-	-	-	-	-	-	-
Cash Flow	(1,500)	(10,500)	(139,750)	(272,958)	(135,212)	33,661	34,761	34,761	34,761	34,761	34,761
Accumulated Cash Flow	(1,500)	(12,000)	(151,750)	(424,708)	(559,930)	(526,259)	(491,498)	(456,738)	(421,977)	(387,216)	(352,455)
Rate of Return (%)	-	-	-	-	-	-	-	-	-	-	-
Present Value at 10%	(1,430)	(10,531)	(120,652)	(316,186)	(404,240)	(384,312)	(365,604)	(348,596)	(333,134)	(319,078)	(306,300)
Present Value at 15%	(1,399)	(9,913)	(108,452)	(275,812)	(347,902)	(332,296)	(318,283)	(306,097)	(295,500)	(286,286)	(278,274)

TABLE 7-5

CASHFLOW PROJECTION
Paraho Process - Base Case
('000 US DOLLARS)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	-
.2036	.2036	.2036	.2036	.2036	.2036	.2036	.2036	.2036	.2036	.2036	.2036	.2036	.2036	.2036	.2036	-
2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	2,015	40,306
654	654	654	654	654	654	654	654	654	654	654	654	654	654	654	654	13,081
957,161	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161	5,957,161	119,143,220
329,472	329,472	329,472	329,472	329,472	329,472	329,472	329,472	329,472	329,472	329,472	329,472	329,472	329,472	329,472	329,472	6,589,441
38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	759
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00
25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00	28.00
2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92
2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19
120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00
110.00	110.00	110.00	110.00	110.00	110.00	110.00	110.00	110.00	110.00	110.00	110.00	110.00	110.00	110.00	110.00	110.00
50,383	50,383	50,383	50,383	50,383	50,383	50,383	50,383	50,383	50,383	50,383	50,383	50,383	50,383	50,383	50,383	1,007,655
18,314	18,314	18,314	18,314	18,314	18,314	18,314	18,314	18,314	18,314	18,314	18,314	18,314	18,314	18,314	18,314	366,274
17,395	17,395	17,395	17,395	17,395	17,395	17,395	17,395	17,395	17,395	17,395	17,395	17,395	17,395	17,395	17,395	347,898
7,215	7,215	7,215	7,215	7,215	7,215	7,215	7,215	7,215	7,215	7,215	7,215	7,215	7,215	7,215	7,215	144,309
4,554	4,554	4,554	4,554	4,554	4,554	4,554	4,554	4,554	4,554	4,554	4,554	4,554	4,554	4,554	4,554	91,080
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
97,861	97,861	97,861	97,861	97,861	97,861	97,861	97,861	97,861	97,861	97,861	97,861	97,861	97,861	97,861	97,861	1,957,216
12,975	12,975	12,975	12,975	12,975	12,975	12,975	12,975	12,975	12,975	12,975	12,975	12,975	12,975	12,975	12,975	259,500
50,125	50,125	50,125	50,125	50,125	50,125	50,125	50,125	50,125	50,125	50,125	50,125	50,125	50,125	50,125	50,125	1,002,500
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
63,100	63,100	63,100	63,100	63,100	63,100	63,100	63,100	63,100	63,100	63,100	63,100	63,100	63,100	63,100	63,100	1,262,000
34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	695,216
									CASH FLOW							
34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	695,216
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	561,020
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	3,970	7,039	7,039	7,039	25,087
-	-	-	-	-	-	-	-	-	-	-	-	2,592	3,013	3,013	3,013	11,630
34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	34,761	28,198	24,709	24,709	24,709	97,478
(87,216)	(352,455)	(317,695)	(282,934)	(248,173)	(213,412)	(178,652)	(143,891)	(109,130)	(74,369)	(39,608)	(4,848)	23,350	48,060	72,769	97,478	97,478
-	-	-	-	-	-	-	-	-	-	-	-	.41	.80	1.16	1.48	1.48
(319,078)	(306,300)	(294,684)	(284,123)	(274,523)	(265,795)	(257,861)	(250,648)	(244,091)	(238,130)	(232,711)	(227,784)	(224,151)	(221,252)	(218,626)	(216,234)	(216,234)
(286,286)	(278,274)	(271,367)	(265,248)	(259,980)	(255,399)	(251,415)	(247,951)	(244,939)	(242,320)	(240,042)	(238,062)	(236,665)	(235,600)	(234,674)	(233,869)	(233,869)

financial returns of a given level. This comparison is even more severe when borrowed funds are used for 75% of project financing.

If we examine the world oil price needed to support various financial objectives, as applied to the HYTORT projections, we find that the base case (oil at $29) provides a return on investment of only 1.3%, with project financing repaid in 16 years after production start-up. If a return on investment of 11% is required, the world oil price would have to be $36.87 in the all-equity case, or $44.80 if borrowed funds are used for 75% of project financing.

A requirement for 15% return on investment would require a world oil price of $40.63 (or $49.54 if funds are borrowed).

If we assume that metals can be recovered and sold to yield an additional net revenue of 10%, the rate of return on the base case (with oil at $29) increases from 1.3% to 3.4%. Conversely, if we require a return on investment of 11%, the oil price required would reduce from $36.87 for the original case to $34.97, with metals revenue.

7.9 CONCLUSIONS

The financial analysis has shown that an oil shale project located in southern Ontario can be attractive. Furthermore, it appears that processes that maximize oil yield, such as HYTORT, have a definite economic advantage over those that do not, despite higher capital and direct operating costs.

The projections are based on estimates of capital and operating costs for projects in other locations. An analysis based on process parameters, engineering and cost estimates for the specific site will undoubtedly allow more meaningful analysis. We are persuaded to conclude, however, that the oil price : costs : financial relationships developed in this study are sufficiently attractive to warrant the more detailed studies which are so badly needed.

The prime factor which affects projects of this magnitude is total capital cost. Further process investigations will allow costs to be estimated with far more confidence. Of possibly greater importance, the question of daily throughput can be studied based on real process parameters; one objective being to see whether plants of 10% to 25% of the capacity used in this analysis would make economic sense. The problems of management and engineering associated with mega-projects could then be put aside and allow the project to be established at a more manageable scale.

Important process parameters also require further study. The technical and financial viability of preconcentration of the shale needs careful investigation. The cost to recover byproduct metals should be determined and the relevant metal markets examined.

8. END-PRODUCTS AND ENERGY ANALYSIS

3.1 GENERAL

A wide range of end-products could potentially be extracted from Ontario oil shales. These include:

Energy Products	– liquid synthetic fuels; substitute natural gas; thermal power; or, any combination of these
Process Byproducts	– ammonia; sulphur; coke; pitch; asphalt
Byproduct Metals	– vanadium; nickel; chromium; silver; molybdenum
Byproduct Raw Materials For	– the cement industry; brickbuilding; road surfacing; aggregates; fillers

In Ontario, as in the rest of North America, the focus of future investigations will most likely be directed toward the production of transportation fuels to augment supplies of conventional crude. Ontario has an abundant supply of electric power, but almost no indigenous resources of liquid and gaseous fuels.

In the following sections, the potential product slate that could be achieved by optimum liquid synthetic fuel production from Ontario oil shales, is first reviewed. The relationship between the thermal energy required to extract these products relative to their energy value is then examined. Finally, some of the potential non-energy byproducts of the oil shales of Ontario and their potential to contribute additional revenue to the operation are reviewed.

8.2 ENERGY PRODUCTS

It is unfortunate that no attempt has yet been made to characterize raw shale oil from Ontario oil shales. It has therefore been necessary to rely upon results of research on product characterization of the Devonian Eastern USA shales. As previously indi-

cated, there are many similarities between the organic geochemistry of these shales and the oil shales of the Kettle Point and Long Rapids Formations. This extrapolation is, however, less valid for the oil shales of the Collingwood Formation.

Table 8-1 shows some of the product characteristics of raw and hydrotreated shale oils from the Eastern USA produced by different processes. Comparative data are also shown for western Canada crude oil and for raw and upgraded bitumen from the Athabasca oil sands. Some comparative data on Western USA shale oils are also included.

The table shows that, although most properties of the raw shale oils derived from Eastern USA shales are similar to the raw oils derived from the oil sands, the distillation results indicate that the volume yield below 700°F is significantly higher from the oil shales. This might indicate that middle distillates, such as jet fuel and diesel oil, could be produced from shale oil under upgrading conditions that are less severe than those currently used for oil sands. Furthermore, of all the raw oils shown, those produced by the HYTORT process have a significantly lower pour point than the others.

In general, the results also show that the raw Eastern USA shale oils have a lower pour point and a higher yield of middle distillates than their western counterparts. On the other hand, they have a lower API gravity and a higher percentage of both sulphur and aromatics. Hydrotreating of these oils resulted in increased yields of middle distillates and a reduction in sulphur content.

It is therefore possible to extrapolate that an oil, rich in middle distillates, could also be obtained from the oil shales of Ontario. This oil would most likely be suitable for aviation turbine and diesel fuels.

8.3 BYPRODUCTS

Many potential metal and raw material byproducts could be recovered from an oil shale industry here in Ontario. The results of trace-element analysis on the Kettle

TABLE 8 - 1

COMPARISON OF OIL PROPERTIES

Description	Conventional Crude Oil Pipeline Quality	Synthetic Crude Oil Upgraded	BITUMEN		US SHALE OIL				
					EASTERN				WESTERN
					HYTORT		DRAVO		UNION B
			Athabasca Raw	Cold Lake Raw	Raw	Hydrotreated	Raw	Hydrotreated	Raw
Properties									
Gravity (° API)	38	31	11	11	12–24	28–32	12	29	22
Density (g/mL)	0.835	0.871	0.996	0.995	0.91–0.99	0.86–0.89	0.99	0.88	0.92
Nitrogen (wt%)	0.05	0.04	0.4	0.31	1.5–2.0	0.03–0.08	1.1	0.005	1.8
Sulphur (wt%)	0.4	0.1	3.7	4.4	0.8–1.3	0.002–0.005	3.9	0.001	0.8
Arsenic (ppm)	—	—	—		1–3	ND	100	ND	50
Pour Point (°F)	21	-49			-20– -45	-20– -45			60
Yield below boiling point of 700°F (vol%)	63	73	18		65–85	80–90	40–50	66	37–58
Pentane Insoluble (wt%)	—	—	8	11.5 (heptane)	9	ND	3.2	ND	
Aromatics (vol%)					50	40	55	53	
Sources of Information	(1)	(1)	(1, 2)	(2)	(3)	(3)	(4)	(4)	(5)

(1) Dautzenberg and Yeung 1984
(2) Sumida et al. 1984
(3) HYCRUDE 1984
(4) Lyzinski and Jones 1984
(5) Dhondt 1980

Point Formation show significantly anomalous contents of vanadium, nickel, chrome, molybdenum, and silver. While the uranium content of the Kettle Point oil shale appears to be considerably lower than that of other Devonian shales, the vanadium content may be considerably higher.

Extraction of some of these metals may be technically feasible and could contribute to the overall revenues of an oil-shale operation. Table 8-2 shows the potential contribution to revenues for a 30,000 ton/d oil shale plant, based upon concentrations of these elements in the Kettle Point oil shale. The values that have been applied to the products and byproducts are as follows:

Vanadium	= US $ 3.30/lb
Nickel	= US $ 3.16/lb
Chromium	= US $ 2.58/lb
Molybdenum	= US $ 4.29/lb
Silver	= US $ 6.00/troy ounce
Sulphur	= US $120.00/long ton
Oil	= US $ 26.00/bbl

It should be clearly understood that this table is purely speculative and that no attempt has been made to establish the technical or economic feasibility of recovery of these byproducts. The purpose of this table is to demonstrate that this is an area that needs further investigation.

TABLE 8-2

TRACE ELEMENTS – KETTLE POINT FORMATION

Element	Concentration in Shale (ppm)[1]	Amount Recovered from 30,000 ton/d Plant	Value[2]	
			$	%
V	590	14.5 tons	95,829	15.3
Ni	149	3.7 tons	23,358	3.7
Cr	92	2.3 tons	17,016	2.7
Mo	150	3.7 tons	31,752	5.1
Ag	1	49 lbs	3,528	0.6
S		742 long tons	89,040	14.3
Oil		14,000 bbl[3]	364,000	58.3

[1] Analyses by University of Waterloo of samples taken from OGS borehole KP 24

[2] Values shown are gross values in feed to which an 82% metals recovery factor has been applied.

[3] HYTORT process.

8.4 NET ENERGY ANALYSIS

8.4.1 GENERAL

The amount of energy required to extract energy from oil shales can be assessed by net energy analysis. Several sophisticated techniques have been developed to determine energy input to output ratios and there is, as far as is known, no one standard method that has widespread acceptance.

Our approach to the subject is a relatively simple one that has much in common with an operating cost estimate. No 'capital' energy requirements are included in our analysis, nor is the effect of external energy requirements considered, such as the amount of energy required to produce the electricity and natural gas used in the process. The objective is to determine if the energy extracted from the shale is greater than that required for mining, crushing and processing.

The same two cases are presented as were used in the economic scenario. It is assumed that the Kettle Point oil shale will be exploited by open-cast mining, crushing and retorting in either the Paraho or HYTORT process. These assumptions are shown on Table 8-3. Many of the energy values are extrapolated from various studies completed on these processes for Eastern USA Devonian oil shale and adjusted accordingly for expected yields from the Kettle Point oil shale. A brief discussion of some of the details follows.

TABLE 8-3

ENERGY ANALYSIS ASSUMPTIONS

DESCRIPTION	PARAHO	HYTORT
Oil Yield FA	40 L/t (9.5 US gal/ton)	40 L/t (9.5 US gal/ton)
Hydrogen Retorting Yield	N/A	91 L/t (21.8 US gal/ton)
Expected Process Yield	47 L/t (11.3 US gal/ton)	82 L/t (19.6 US gal/ton)
Shale Mined	30,500 t (33,600 tons)	34,000 t (37,500 tons)
Feed to Retort	27,210 t (30,000 tons)	27,210 t (30,000 tons)
Gross Heating Value Oil	41,170 MJ/t (17,700 BTU/lb)	45,357 MJ/t (19,500 BTU/lb)

8.4.2 ENERGY INPUTS

Energy inputs for mining and crushing, based upon our own knowledge, were set at 26 MJ/t (6.5 kWh/ton) and 14 MJ/t (3.5 kWh/ton) of mined shale. These figures were then adjusted upwards for loss of fines during retort feed preparation. In the case of Paraho, some 12% of the mined material is lost, while some 20% of the material is lost during feed preparation for HYTORT processing. Processing inputs for Paraho were taken directly from a paper written by Hilleke and Hanna (1981). Processing inputs for a HYTORT 50,000 bbl/day plant were supplied to us by HYCRUDE and adjusted accordingly.

8.4.3 ENERGY OUTPUTS

Energy outputs for shale oil were determined by relating expected process yields to the gross heating value of the product. The energy value of light oil, high-BTU gas, electrical power, sulphur, and ammonia were all extrapolated from similar studies on Eastern USA shales.

8.4.4 DISCUSSION

The results of the net energy analysis study are shown on Table 8-4. In our opinion, these results show that, in both cases, one can expect to ultimately obtain more energy out of the oil shales than is required for processing. On a comparative basis, the two processes have almost the same net energy ratio. It is of interest to note, however, that although the HYTORT process appears to use 16% more energy than Paraho, it also outputs some 38% more energy. Furthermore, the HYTORT process can yield almost twice the amount of energy in the form of oil than that yielded from the Paraho process.

TABLE 8-4

NET ENERGY ANALYSIS

DESCRIPTION	PARAHO (MJ/t feed)	HYTORT (MJ/t feed)
ENERGY INPUT		
Mining	29	32
Crushing	16	17
Processing	1,512	1,749
Total Input	1,557	1,798
ENERGY OUTPUT		
Shale Oil	1,382	3,489
Light Oil	448	—
Gas	700	—
Electric Power	133	—
Sulphur	62	190
Ammonia	—	69
Total Output	2,725	3,748
NET ENERGY RATIO	1.8 : 1	2.1 : 1

9. EXPECTED ENVIRONMENTAL EFFECTS

9.1 GENERAL

At present, the oil shale industry in Ontario is in the conceptual stage. Therefore, an assessment of its expected environmental effects must be based on the literature generated from the oil shale industry in the United States. Currently, oil shale is being extensively developed in several western states (Utah, Colorado, Wyoming), but has not been mined beyond the pilot-plant stage in the Eastern USA. However, since Ontario oil shales differ both chemically and physically from Western USA oil shales and are similar to those in the Eastern USA, the environmental evaluation will focus on data gathered from Eastern oil shale studies.

Preliminary investigations into the feasibility of mining Ontario oil shales (Chapter 4) have shown that the shale would be mined by the open-cast method and consequently would be processed by surface retorting. Therefore, the effects of mining and processing oil shale by these methods are emphasized in this chapter.

Many of the environmental effects associated with oil shale are similar to those of other mining and refining operations. However, the shale retorting step is unique to this industry and results in the production of gaseous and liquid effluents, plus solid residues, which contain potentially hazardous inorganic and organic pollutants. These concerns are addressed under Sections 9.2 Water Quality, 9.3 Air Quality, and 9.4 Land and Biota. Where possible, mitigative measures are suggested.

9.2 WATER QUALITY

Water may be used at an oil shale plant for mining operations, dust control, steam and power generation, compaction, revegetation of processed shale, potable water supply, prerefining, and other uses. Each of these uses produces an effluent that must be collected, treated and discharged. The types of effluents produced include mine

waters, brines from treatment processes, storm water run-off, and various process waters. Many of these effluents are normally found in other types of industrial operations and can be treated using conventional control technologies (Fox and Phillips 1980). However, the process waters — retort water and gas condensate — are unique to oil shale retorting, due to their volumes and/or composition.

9.2.1 MINE WATER

It is very likely that the development of the mine will disrupt normal groundwater flow by interfering with subsurface aquifers. This results in the diversion of groundwater into the mine. As well as mine seepages from trapped aquifers and springs, surface run-off and rain water will also accumulate at the bottom of the mine. These waters must be removed, both before mining operations can be carried out and continuously during the operation of the mine.

Mine waters will become contaminated with wastes from drilling and mine operations and thus may contain high amounts of dissolved inorganic substances, trace elements, oil, and grease (Fox and Phillips 1980). The quality and quantity of this water will vary with mine location, oil shale zones developed, and mining method (Brady and Rutledge 1979).

Mine waters occur in very large volumes, but most can be recycled for on-site use in dust control or for process purposes. Any mine water that is not re-used can be monitored and treated, if required, before being discharged.

9.2.2 PROCESS WATERS: RETORT WATER AND GAS CONDENSATE

The waste waters with the most potential for adversely affecting the environment at oil shale plants are the retort water and process condensate. These waters are produced within a retort as a vapour that is condensed with the oil or gas and are produced in large volumes. Up to 38 L of retort water per tonne of shale (10 US gal/ton) may be produced, with an average range from 7.6 to 18.9 L/t (2–5 US gal/ton) (Nowacki 1980). The retort water is in contact with oil and shale during its production

and collection. Analysis of this water indicates that it has high concentrations of solids, ammonia, ammonium ions, sodium, magnesium, bicarbonate, carbonate, sulphate, and chloride ions (Fox and Phillips 1980; Nowacki 1980). The relative concentrations of inorganics depend on the characteristics of the oil shale and the retorting process. Organic constituents are mainly mono- and dicarboxylic acids. The environmentally important elements, present in both retort and condensate water, are trace metals such as lead, mercury, molybdenum, selenium, arsenic, zinc, manganese, chromium, and vanadium.

The gas condensate, which leaves the retort as a vapour, contains lower concentrations of dissolved solids than retort water, and higher concentrations of dissolved gases such as ammonia, hydrogen sulphide, and carbon dioxide. The published data on process condensate quality is generally not satisfactory for assessing its environmental impact.

The total volume of waste water to be discharged by shale oil production operations will vary with retorting method. Above-ground retorting facilities, which will most likely be used in Ontario, may be able to re-use most of the retort water. There are several water-consuming operations at oil shale plants that can utilize the process condensate after suitable treatment. Some of the major water requirements are moistening and revegetation of spent shale, dust control at the mine-site, cooling water make-up, and boiler feed water (Hicks and Probstein 1982). The latter two 'waters' require considerable upgrading. Theoretically, all the process condensate can be re-used, but it is realistic to assume that there will be substantial waste water discharges.

Substances from retort water which could affect groundwater quality are:

- High salinity: toxic to most cover crops; may adversely affect drinking quality of groundwater
- High nitrogen concentrations, which yield nitrate on oxidation; excessive nitrogen loading would result in nitrate contamination of the groundwater
- Presence of trace metals and organics

Fox and Phillips (1980) state that the treatment of gas condensate appears to be straightforward, but treatment of retort water is more complex and difficult. However, toxicity tests on aquatic biota exposed to a series of treated retort and condenser waters suggest that the toxicity of these waters can be dramatically reduced by currently available waste water treatment methods (Bergman et al. 1982).

9.2.3 MISCELLANEOUS LIQUID WASTES

Several other kinds of liquid wastes are associated with shale oil recovery and processing. These could include cooling-tower blowdown, boiler water blowdowns (with high salt and trace metal levels), and sour water from refining operations (oily cooling waters and waters with ammonia and hydrogen sulphide content) (Nowacki 1980). Data on these waste streams are limited.

The upgrading of crude shale oil results in pollutants common to petroleum refinery operations. The characteristics of wastes discharged from these operations depend on the nature and source of the crude oil processed, design and type of production facilities, cooling water requirements, housekeeping and control practices employed (Nowacki 1980).

9.2.4 SURFACE/GROUNDWATER

Contamination of both surface and underground waters is a potential hazard associated with surface mining. In general, the physical disturbance created by mining may cause deeper saline groundwater to contaminate upper good quality waters. Groundwater or surface water contamination might also be caused by materials used in well drilling. Improperly cased wells or well blowouts would result in leakages of brine, contaminated retort water, retort gas, and shale oil (Nowacki 1980).

In any mining activity, there is a potential for increased erosion and sedimentation as a result of construction or operation activities. The construction of sediment retention structures, coupled with effectively applied revegetation techniques help to limit the overall amount of erosion, surface run-off, and sedimentation.

Another consequence of surface mining is the interruption of small streams and drainages, and the possibility of alteration of other drainage patterns (Hale 1980). This environmental impact is not unique to oil shale mining and disposal, and may be mitigated to a large degree by building effective drainageways or sedimentation ponds.

9.2.5 LEACHATE AND RUN-OFF FROM WASTE DISPOSAL PILES

Disposal of solid wastes from the mining and processing operations may have considerable effect on water quality.

Spent shale is the major solid waste from mining and retorting processes. The chemical and physical characteristics of retorted shales are dependent on the properties of the raw shale, the particle size following crushing, and on the retorting method and temperature. Spent shale is approximately 85% of the original raw shale mass, but during crushing and retorting, the volume of the shale expands by 10% to 30% (Redente et al. 1980).

The disposal of spent shale is potentially the most serious source of environmental impact of a surface-retort oil shale facility. The high content of water-soluble materials in the spent shale creates a large potential for environmental contamination from leaching. If uncontrolled, leachate from disposal sites may increase the salinity, sediment, dissolved solids, and heavy metal levels in natural waters.

There have been extensive leaching studies carried out on trace elements in Western USA oil shales, but these are not applicable to Eastern shales. The Western oil shales are mainly carbonates or marlstones, while those in the east are primarily silicates (Tian and Ehmann 1984). Eastern oil shales generally have high pyritic iron and low carbonate contents. Therefore, the trace element distributions in the Eastern and Western shales are quite different.

In a laboratory study of elemental release from Kentucky raw and retorted shales by leaching, Tian and Ehmann (1984) found that the pH value for most leachates was lower than six. In a pilot-plant study by Koppenaal et al. (1984), analysis of the

leachates indicated that all leachates in contact with raw or retorted shale are very acidic, with a pH in the range of 2.8–3.2. This implies that the acid-producing potential of Eastern oil shale is appreciable. This is due principally to the presence of pyrite in the shale, which is oxidized in the presence of air and water to produce sulphuric acid.

Leachate pH varies with pyrite content and retorting conditions, both of which are important in the prediction of the environmental effect of retorted shale, since the dissolution of trace elements in the leachate or surface run-off increases with decreasing pH.

Tian and Ehmann's (1984) study showed that of the 38 elements in leachates from both raw and retorted shales, only cadmium (Cd) appeared to occur in concentrations high enough to be of environmental concern. Fish and certain invertebrates have been found to be sensitive to low levels of cadmium in water (U.S. Environmental Protection Agency 1976). Tian and Ehmann further suggested that most of the elements in retorted shales exhibit decreased solubility and mobility compared with those in raw shale. The implication is that piles of raw shale exposed to natural leaching may pose more serious environmental problems than retorted-shale waste. In another study on Eastern oil shales, Paciorek et. al. (1983) concluded that the raw oil shales, with their relatively high pyrite content, present a higher potential for acid drainage, but that the spent shales do not seem to present an environmental hazard. They also suggest, however, that there are insufficient data to assess potential leachate production from the spent shales or to predict the effect of co-burial of spent and raw shale on species mobilization.

In addition to effects from leaching, surface and groundwater potentially may be contaminated by run-off and erosion from the disposal piles.

Various methods of stabilization and control, several of which are listed below, may be employed as mitigative measures (adapted from Fisher 1980; Nowacki 1980; Shogren 1981):

- The tailings can be covered with top soil for vegetative stabilization
- The spent shale can be chemically treated to form a layer impermeable to air and water
- The piles can be compacted to aid in decreasing infiltration of water as well as reducing erosion
- The piles can be sloped and contoured to control run-off
- Drainage ditches can be located around the pile to prevent surface water from percolating through
- The disposal piles should be kept moist to aid compaction and stabilization
- The bottom and sides of the disposal areas can be lined with an impermeable material to prevent leachate from entering ground or surface waters

Even though preliminary studies indicate that spent shale will be neither hazardous nor toxic, the possible impacts of disposing of many tonnes of shale per year in a mined area that has had groundwater and surface-flow characteristics disrupted is relatively unknown (Shogren 1981).

9.3 AIR QUALITY

Atmospheric emissions can arise from several oil shale mining activities: blasting, mine equipment use, overburden and raw shale transport and disposal, crushing, retorting, and refining operations. These emissions are not unique to oil shale mining and processing, and should respond to conventional control techniques, a few of which are outlined at the end of this section. Hence, only the most common emissions and sources are discussed below.

9.3.1 DUST AND PARTICULATE MATTER

Dust and particulate matter are the major atmospheric emissions expected from oil shale mining and processing. Suspended particulates persist in the atmosphere longer than larger particles ('dustfall'), are often responsible for reduction in visibility, and take part in reactions with other air pollutants (World Health Organization 1979).

Particulate matter is generated from blasting, raw- and spent-shale handling and disposal, raw- and spent-shale dust in process gas streams from retorting, fuel combustion, and site activites which generate fugitive dust (Ertugrul 1980). Open-cast oil shale mining, as compared to underground mining, is expected to produce relatively large amounts of fugitive dust and particulate emissions from drilling, blasting, loading, and hauling. This reflects the greater mine surface area exposed and the greater total tonnages of overburden, waste and ore handled (Brady and Rutledge 1980). Conventional technology to control dust and particulate matter emissions from various discharges is available, so it is not expected that these emissions will be an environmental problem.

9.3.2 SULPHUR DIOXIDE

Sources of sulphur dioxide are construction and mining machinery, transportation vehicles, fuel combustion from process heaters, and tail gases of sulphur recovery operations. The retort gas and the hydrocarbon gases produced during shale oil upgrading may contain hydrogen sulphide. These gases can be used as fuel in the retort and other process heaters (Domahidy et al. 1983). The hydrogen sulphide is evolved during retorting from inorganic and organic constituents in the oil shale mineral matrix. If not removed by environmental control equipment, the sulphur would be released as sulphur dioxide following oxidation of the fuel gas (Fruchter et al. 1982).

Environmental abatement systems require information on the expected gas flow rates and gas compositions, both of which are presently unknown. However, there are basically two options for the removal of sulphur contained in the raw retort gas:

1. Removal of the reduced species (e.g., hydrogen sulphide) before oxidation of the fuel gas.
2. Removal of sulphur dioxide by scrubbing the flue gas after oxidation.

9.3.3 NITROGEN OXIDES

Nitrogen oxides are formed in almost every step of the oil shale process. Nitrogen is chemically bound with organic components of the kerogen structure (Nowacki 1980) and is released as nitrogen oxides and ammonia during the retorting process. Also, if combustion temperatures are high enough, nitrogen oxides can be formed from atmospheric nitrogen. It is expected that equipment used in oil shale retorts will be designed to run at low temperatures to minimize this effect. Combustion of product gas and shale oil, exhaust fumes from construction and mining machinery, transportation vehicles, and explosives also generate nitrogen oxides (Domahidy et al. 1983).

9.3.4 CARBON MONOXIDE

The sources of carbon monoxide from oil shale mining and processing are fuel combustion from process heaters, construction and mining machinery, transportation vehicles, explosives, and combustion of the residual carbon in spent shale. These sources are readily controlled.

9.3.5 HYDROCARBONS

The potential sources of hydrocarbon gas emissions are the oil storage tanks, leaks and spills from retorting, oil upgrading, ammonia recovery, and fuel gas processes. The extensive use of large loading and haulage equipment and explosives will result in additional emissions of hydrocarbons.

Various hydrocarbon species have been measured in the off-gases of several retorts and the relative percentages of aliphatic and aromatic hydrocarbons are dependent upon the type of oil shale and the type of retort. Controls such as thermal oxidizers and flare stacks are considered necessary during emergencies or process upsets (Fruchter et al. 1982). The controls for these are available and have been applied to many modern chemical plants.

9.3.6 TOXIC ORGANIC COMPOUNDS

Fruchter et al. (1982) addressed the problem of toxic organic compounds released in various stages of oil shale processing. Compounds such as polycyclic aromatic hydrocarbons and aromatic amines exist in the vapour phase during retorting and combustion and upon cooling become associated with oil mist droplets, soot and spent shale particles suspended in the retort off-gas. Removal of toxic and carcinogenic compounds, such as benzo(a)pyrene in retort off-gas is dependent on the efficiency of particulate removal and on the removal of organics from the vapour stream using incineration or activated carbon.

Another potentially important source of air emissions of toxic organic compounds is the use of recycled water in scrubbers or in quenching hot incinerated gas. Fruchter et al. (1982) suggested that contaminants build up in the recycled water and further contaminate the air emissions.

9.3.7 ENVIRONMENTAL CONTROL

There is a great deal of uncertainty in determining the effects of airborne pollutants from oil shale mining and processing. There have been few, if any, demonstrations of emission control devices on a commercial size unit, so the potential effectiveness of such controls is unknown. However, many techniques are available; several of these, as outlined by Nowacki (1980), are listed below.

Air pollution control during surface mining may include the following measures:

- Prewatering and wetting for dust control
- Treating with dust suppressants such as oil emulsions, polymers, soil stabilizers
- Restricting construction and mining vehicle activity
- Correct use of drills and explosives to minimize fugitive dust

Dust suppression during shale preparation (crushing and screening) may be accomplished by several techniques:

- Crushers enclosed with fabric filter dust collector baghouse
- Crusher units equipped with water sprays or wet scrubbers

- Dust collected from baghouse slurried to the processed shale moisturizer
- Conveyor covered and transfer points equipped with dust suppression systems

Retorting and refining operations may include the following air pollution control techniques:

- Use of purified gas to minimize particulate emissions
- Desulphurization in sulphur recovery plant for untreated gas
- Use of scrubbers to remove shale dust from flue gas and vapours
- Use of steam stripping to remove hydrogen sulphide and ammonia in sour water
- Incineration or use of activated carbon for removal of trace organics

9.4 LAND AND BIOTA

The activities related to developing an oil shale mine, such as road construction and site preparation, are common to mining in general. Consequently, their effects are well known and will be mentioned only briefly.

Clearing and grading access routes and clearing the mine site involves the removal of all surface features, both natural and man-made. Therefore, the effects are severe; complete removal of vegetation, loss of wildlife habitats, removal and disposal of top soil, possible loss of archaeological sites, and general loss of aesthetic quality. In the case of the Kettle Point Formation in Ontario, farmland would be lost for many years, probably at a rate of up to one km^2 per year. Ameliorative measures are few:

— Avoidance, if possible, of environmentally sensitive areas and of unnecessary clearing

— Transplanting of rare or endangered plant species

— Site clearance undertaken in such a way as to enable wildlife to flee safely

— Expeditious road building to lessen erosion

— Check for possible archaeological sites and, if found, allowance for salvage digs to be carried out

— Storage of top soil for future use in land reclamation and revegetation

As mentioned previously, both vegetation and wildlife species are negatively influenced by a mining development. Not only is vegetation completely removed, but plant species downwind of the mine area may be affected by atmospheric emissions and excessive dust, resulting in reduced growth and reproduction. However, vegetation may be re-introduced to a mined site during reclamation activities, which include recontouring the land, utilization of previously removed top soil, and careful selection of plant species.

Removal of vegetation produces severe disturbance to the indigenous wildlife through loss of habitat. This effect may be considered temporary, however, due to the fact that wildlife populations will re-inhabit a site after revegetation takes place. Wildlife are also disturbed by human activity and by noise generated from mining operations and would likely emigrate from the area during the period of heavy activity. Again, this may be considered a short-term effect.

Aquatic life may be affected by oil shale mining, due to increased sedimentation and turbidity of the water, and to the possible contamination of water from effluents and leaching (Hale 1980). However, as discussed under Section 9.3, these effects can be at least partially alleviated through control procedures.

9.5 SUMMARY

Many of the environmental effects associated with oil shale are similar to those of other mining and refining operations. Therefore, proper control procedures, many of which are currently practised, can effectively reduce the impacts expected from mining Ontario oil shales. Several environmental concerns are listed below.

- Water is used extensively during oil shale mining and processing; consequently, many effluents are produced that must be collected, treated and discharged. Most of these can be treated using conventional control technologies.
- The waste waters with the most potential for adversely affecting the environment are the retort water and process condensate, both of which contain potentially toxic organics, inorganics and trace metals. Treatment of the gas condensate is relatively straightforward, but treatment of the retort water is more complex and difficult.

— Contamination of both surface and underground waters is a potential hazard associated with surface mining in general. Such impacts may be mitigated to a large extent by existing control technology.

— Disposal of solid wastes from the mining and processing operations may have considerable effect on water quality. If uncontrolled, leachate from both raw- and spent-shale disposal sites may increase the salinity, sediment, dissolved solids, and heavy metals in natural waters. The acid-producing potential of Ontario shales is considerable.

— Atmospheric emissions arising from several oil shale mining activities are not unique to the oil shale industry and should respond to conventional control techniques. Dust and particulate matter are expected to be the major atmospheric emissions, with lesser amounts of sulphur dioxide, nitrogen oxides, carbon monoxide, hydrocarbons, and several organic compounds emitted.

— The activities related to developing an oil shale mine are common to mining in general. Consequently, the effects on the land and biota are well-known. The adverse effects to the land, vegetation and wildlife can be considered short-term, if effective reclamation and revegetation techniques are employed.

10. CONCLUSIONS AND RECOMMENDATIONS

10.1 CONCLUSIONS

Our evaluation of the process options for Ontario oil shales leads to the following general conclusions:

- — Ontario has vast resources of latent energy in oil shales of the Kettle Point, Long Rapids and Collingwood Formations;
- — it is technically feasible to recover this energy and to produce a light oil rich in middle distillates suitable for use as transportation fuel; and
- — further work is required to develop the process technology and to more fully evaluate the technical and economic benefits of an oil shale industry in Ontario.

More specific conclusions from each of the individual studies follow:

1. Ontario has oil shales in three formations, which together have an overall shale oil resource potential of 8,480 million m^3 (53 billion bbl) by FA and 16,960 million m^3 (106 billion bbl) by hydrogen retorting.
2. One of these oil shales, within the Devonian Kettle Point Formation in the Sarnia area, appears to have significantly higher oil yields than any of the others. A 10 m section of this material can yield 40 L/t (9.5 US gal/ton) from FA and this yield could be more than doubled by retorting in the presence of hydrogen under pressure.
3. This material is so similar lithologically and chemically to the Devonian oil shales of the Eastern USA, that much of the research work carried out in the eastern United States can be extrapolated to the Kettle Point oil shales.
4. From both a technical and economic standpoint, it is likely that Ontario oil shales would be mined by open-cast rather than underground methods.
5. Were there an urgent need to develop this resource immediately, it would most likely be exploited by the Conventional route (i.e., mining, crushing and surface retorting).
6. Beneficiation by kerogen concentration may have potential to improve overall oil yields and reduce capital and operating costs. However, further work needs to be done to examine energy requirements of this additional processing step, to determine retorting parameters for the concentrate and to evaluate the comparative economic benefits of this step.

7. Of the surface retorting processes currently available or under development, hydrogen retorting processes, such as HYTORT, would provide the best technical option for Ontario oil shale development, because it maximizes the oil yield from the resource.

8. Other types of extraction technology, which may have application to Ontario oil shales, include:
   - superheated steam retorting;
   - flash hydropyrolysis;
   - fludized bed retorting; and
   - thermal solution.

9. Although any economic projections for oil shale development are preliminary in nature, our studies have shown that an oil shale project located in Ontario could be financially attractive. Furthermore, it appears processes that maximize oil yield, such as HYTORT, have definite economic advantages over those that do not, despite higher capital and direct operating costs.

10. Although no product characterization has been performed on Ontario shale oil, extrapolation of data from Eastern USA shale oils suggests that a light oil rich in middle distillates could be produced from Ontario shales.

11. Preliminary net energy analysis for mining and processing of these shales has demonstrated that more energy can be produced from these shales than is required for processing.

12. Recovery of valuable metal byproducts from the spent shale may be worthwhile, although the technical and economic feasibility of this step is not known.

13. Many of the environmental effects associated with oil shale are similar to those of other mining and refining operations. Therefore, proper control procedures, many of which are currently practised, can effectively reduce the environmental impact of oil shale development in Ontario.

Finally, while it is true that many of the world's oil shale projects have been temporarily abandoned due to low crude oil prices, it is also true that the development of an oil shale resource can take ten to fifteen years. We believe that the time to initiate the orderly development of specific process technology for Ontario oil shales is now.

10.2 RECOMMENDATIONS

In preparing our recommendations, we have been guided by the principle that process technology development should, initially at least, take precedence over further resource assessment of Ontario oil shales. The current resource assessment program has indicated significantly higher yields for the Kettle Point Formation compared to the Collingwood Member. While we have very few results for the Long Rapids Formation, we believe that these oil shales, in general, are very similar to those of the Kettle Point Formation. Therefore, we recommend that a long-term program of process technology development testing and evaluation be initiated immediately using large samples of Kettle Point oil shale.

The overall objectives of this program would be:

- to develop a process for the production of synthetic transportation fuels from the oil shales of the Kettle Point Formation; and
- to evaluate the technical and economic benefits of this process.

The program for this project should include:

- sample acquisition by core drilling;
- HYTORT testing of approximately 10 kg of raw shale, at mini-bench-scale to establish process yields;
- metallurgical test work to develop a flowsheet and prepare a kerogen concentrate;
- test work to determine total process energy requirements;
- retort testing of the kerogen concentrate to determine retorting parameters and establish process yields; and
- a comparative technical and economic evaluation of both process routes.

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APPENDIX I

MINING COST ESTIMATES

ESTIMATE OF OPERATING COSTS

OIL SHALES IN ONTARIO

Oil shales in Ontario may be mined either by surface or underground methods. Here, both are examined for two mining rates, i.e., 2,000 t/d and 20,000 t/d. These rates will yield approximately 1,000 and 10,000 barrels of shale oil per day, respectively.

The estimates are order-of-magnitude only, and have been derived from the United States Bureau of Mines publication entitled: "Capital and Operating Cost Estimating System Manual for Mining and Beneficiation of Metallic and Nonmetallic Minerals Except Fossil Fuels in the United States and Canada".

Although fossil fuels would appear to include oil shales, the material is more similar in characteristics to some of the metallic and non-metallic minerals than it is to coal or tar sands, which are the more obvious exclusions that might be expected. Therefore, it is considered that the system outlined in the manual is within limitations applicable to the mining of oil shales.

The following criteria have been used to develop these estimates:

	2,000 t/d	20,000 t/d
SURFACE MINING		
Thickness of Formation	3 m	10 m
Waste to Ore Ratio	3:1	3:1
Specific Gravity of Shale	2.1	2.1
UNDERGROUND MINING		
Thickness of Formation	3 m	10 m
Depth of Formation	70 m	100 m

All costs are in 1982 Canadian dollars, based on rates for labour in the mining industry in Ontario. In all cases, it is assumed that the operation will work 350 days per year.

The accuracy of the estimates are not definable in terms of percentage, but rather are considered representative, given that an adequate system of cost controls is imposed

on the operation and that the conditions are generally as defined. Labour costs includes payroll burden but no bonus.

SURFACE MINING

2,000 TONNES PER DAY

Clearing

As mining advances, the surface will have to be cleared of trees, brush, etc. prior to the removal of overburden. Area to be cleared is equivalent to approximately 12 hectares per year. Work will be done by contract in a one- or two-month period in the summer. All costs exclude interest and depreciation.

Estimated Cost per Hectare	
Labour	$1,900
Equipment	490
Supplies	190
	$2,580
Cost per Tonne of Shale Mined	$0.04

Removing Overburden

The thickness of overburden to be removed will average 10 m and will consist largely of till and some weak, barren shales. Since no drilling and blasting will be required, the best method for stripping at this scale of operation may be with scrapers, although the use of trucks and shovels or draglines may also be possible.

With a waste to ore ratio of 3 : 1, approximately 2.1 million tonnes of waste will have to be moved annually, or 6,000 t/d.

Estimated Cost per Day to Excavate, Load and Haul Overburden	
Labour	$2,100
Operation of Equipment	1,500
	$3,600
Estimated Cost per Tonne of Shale	$1.80

Drilling and Blasting Shale

The shale formation will be hard enough to require blasting in order to break it into a size that will permit handling to the process plant. Drilling will be by percussion drills.

Included in this cost is provision for sampling cuttings from the blastholes, thereby providing a basis for grade control.

Considering the thickness of formation, it is envisaged that only one bench will be required to extract all of the shale.

Estimated Cost per Day to Operate Drills, Load and Blast	
Labour	$1,900
Operate Equipment	600
Supplies	800
	$3,300
Estimated Cost per Tonne of Shale	$1.65

Excavating, Loading and Hauling Shale

For this size of operation, the most suitable method of excavation will be rubber-tired front-end loaders, loading into trucks of 20 to 35 tonnes capacity. The average length of haul will be less than 1,000 m one way.

Estimated Cost per Day to Excavate, Load and Haul Shale	
Labour	$2,100
Operate Equipment	1,500
	$3,600
Estimated Cost per Tonne of Shale	$1.80

Restoration During Production

As mining progresses, the mined out areas that have been backfilled with waste will have to be restored to approximately their original contours and also replanted. It is estimated that this will cost about $13,000/hectare.

The same number of hectares that are cleared annually will have to be restored (see "Clearing" above); that is, about 12 hectares.

Estimated Annual Cost of Land Restoration	$156,000
Estimated Cost per Tonne of Shale	$0.22

General Operating Costs

This is an allowance for such items as communications, sanitation, housekeeping, fire protection, electrical, and waste supply.

Allowance for General Operating Costs per Day	$500
Estimated Cost per Tonne of Shale	$0.25

Drainage and Disposal

The cost of pumping and disposing of 5,000 m^3 of water per day recognizes the need for this item. At present, however, data is sufficient to provide for only an average figure.

Allowance for Drainage and Disposal per Day	$150
Estimated Cost per Tonne of Shale	$0.08

Administrative Expenses

This provides for administrative salaries and wages, supplies and services, small tools, and transportation.

Allowance for General Expenses per Day	$425
Estimated Cost per Tonne of Shale	$0.21

Total Operating Cost

All of the above activites are required to deliver shale to the process plant on surface. The costs of crushing or ongoing handling or processing are not included. No provision is made for any camp facilities or transportation of the labour force outside of the mine gate.

Total Cost per Tonne of Shale Mined	
Clearing	$0.04
Removing Overburden	1.80
Drilling and Blasting	1.65
Excavating, Loading and Hauling	1.80
Restoration During Production	0.22
General Operating Costs	0.25
Drainage and Disposal	0.08
Administrative Expenses	0.21
	$6.05

20,000 TONNES PER DAY

Clearing

Approximately 35 hectares of land will have to be cleared annually. This will be done by contract during a two-month period in the summer.

Estimated Cost per Hectare	
Labour	$1,500
Equipment	570
Supplies	170
	$2,240
Cost per Tonne of Shale Mined	$0.01

Removing Overburden

The thickness of overburden to be removed will average 30 m, consisting largely of till and some weak, barren shales above the oil shale. This material may be handled with large capacity earth-moving equipment, such as shovels, draglines or bucket wheel excavators. This type of operation can be planned so that the large equipment can excavate the waste and stack it in the mined-out area without any intermediate handling. The choice of method will depend on a detailed evaluation of the physical properties of the waste, the capabilities of the equipment, and the method of mining the shale.

With a waste to ore ratio of 3 : 1, some 21 million tonnes of waste will have to be excavated annually, or 60,000 t/d. This will have to be a 24-hours per day, 7-days per week operation.

The following costs are for a walking dragline operation, the most likely choice for this kind of operation. The costs for using either shovels or bucket-wheel excavators will be similar. The choice will be made more on technical considerations than on cost.

Estimated Daily Cost to Excavate and Stack Overburden	
Labour	$ 7,500
Operation of Equipment	9,500
	$17,000
Estimated Cost per Tonne of Shale	$0.85

Drilling and Blasting Shale

The 10 m thickness of shale can be mined in a single bench. The drilling will be by rotary drill and hole diameters will be approximately 30 cm.

The costs include bits and steel, blasting supplies, and sampling for grade control.

Estimated Daily Costs to Drill, Load and Blast	
Labour	$ 950
Operate Equipment	475
Supplies	2,800
	$4,225
Estimated Cost per Tonne of Shale	$0.21

Excavating, Loading and Hauling Shale

An operation based on trucks and shovels will be the best choice for mining and delivering the oil shale to the process plant. Shovels will be electric, probably of 10 cubic-yard capacity. Trucks will be 50 to 100 tonnes capacity. Included in the costs are allowances for moving equipment betwen mining faces to facilitate grade control, support of dozers for clean-up, and maintenance of haulage roads. The haul distance will be less than 2,000 m.

Estimated Daily Cost to Excavate, Load and Haul Shale	
Labour	$ 5,700
Operating Equipment	7,500
Supplies	750
	$13,950
Estimated Cost per Tonne of Shale	$0.70

Restoration During Production

The mined-out areas that have been filled with waste cast by heavy equipment (dragline, shovel or bucket wheel) will require a large amount of work to level the ridges and valleys created by the casting operation.

The same number of hectares that are cleared each year for mining will have to be restored; that is, about 35.

The estimated cost per hectare for restoration is $19,000 for a total of $665,000/year.

Estimated Cost per Tonne of Shale..... $0.10

General Operating Costs

This is an allowance for such items as communications, sanitation, housekeeping, fire protection, electrical, and water supply.

Allowance for General Operating Costs per Day $2,700
Estimated Cost per Tonne of Shale..... $0.14

Drainage and Disposal

The cost of pumping, treating and disposing of mine waste is difficult to predict without hard data. At this scale of operation and depth, there may be serious disruption of groundwater with quite heavy inflows, especially in the early phases of operations. Provision is made here to handle 10,000 m^3 of water per day.

Allowance for Drainage and Disposal per Day..... $375
Estimated Cost per Tonne of Shale..... $0.02

Administrative Expenses

This provides for administrative salaries and wages, supplies and services, transportation, and small tools. It includes general office, engineering office, telephone, telex, and computer costs.

Allowance for General Expenses per Day..... $3,500
Estimated Cost per Tonne of Shale..... $0.18

Total Operating Cost

All of the above activities are required to deliver shale to the process plant on surface. The material will be delivered in a form that the plant can accept, but no provision is made for any crushing or rehandling or stockpiling. Labour is assumed to be available at the plant gate.

Total Cost per Tonne of Shale Mined	
Clearing	$0.01
Removing Overburden	0.85
Drilling and Blasting	0.21
Excavating, Loading and Hauling	0.70
Restoration During Production	0.10
General Operating Costs	0.14
Drainage and Disposal	0.02
Administrative Expenses	0.18
	$2.21

UNDERGROUND MINING

2,000 TONNES PER DAY

Development During Production

Prior to start-up, the main haulage systems with provision for ventilation and hoisting to surface will have been completed. The costs here are for development to maintain production. For estimating purposes, it is assumed that development will be one year in advance of production.

The annual requirement for development drifting will be 2,500 m. These drifts will have an average face area of 10 m^2.

Estimated Cost per Metre of Advance	
Labour	$280
Operating Equipment	60
Supplies	190
	$530
Estimated Annual Cost	$1,325,000
Estimated Cost per Tonne of Shale	$1.89

Stope Preparation

It is not possible at this stage to define the size and shape of rooms; however, before production, rooms will have to be opened with cross-cuts to provide ventilation. These cross-cuts will be the full height of the rooms and will have a face area of 10 m^2. Annually, 7,500 m of cross-cut will have to be driven.

Estimated Cost per Metre of Advance	
Labour	$280
Operating Equipment	60
Supplies	190
	$530
Estimated Annual Cost	$3,975,000
Estimated Cost per Tonne of Shale	$5.68

Room-and-Pillar Mining

Development during production and stope preparation will yield a significant tonnage of oil shale.

Estimated Annual Tonnage	
Development	52,500
Stope Preparation	157,500
	210,000
Production Required from Rooms; Annual Tonnage	490,000
Production Daily Tonnage	1,400
Estimated Daily Cost	
Labour	$1,200
Operating Equipment	575
Supplies	1,400
	$3,175
Estimated Cost per Tonne of Shale	$2.27

Load, Haul and Dump

Ore will be removed from the rooms by rubber-tired load–haul–dump units and delivered to a dumping point on the main conveying system. The average haulage distance will be 500 m.

To facilitate handling of the shale, there will be a grizzly and pneumatic breaker at the dump point. This operating cost is included here.

Estimated Cost per Day	
Labour	$2,100
Operating Equipment	1,900
	$4,000
Estimated Cost per Tonne of Shale	$2.00

Conveyor Haulage to Surface

As mining advances, the haulage distance will increase and will average about 3,000 m during the first ten years of operation. Shale will be delivered to the plant on surface.

Estimated Cost per Day	
Labour	$200
Operating Equipment	20
Supplies	100
	$320
Estimated Cost per Tonne of Shale	$0.16

General Operating Costs

This includes such general items as communications, sanitation, housekeeping, fire protection, and electrical that are not directly attributed to specific mine operations.

Estimated Cost per Day	
Labour	$1,100
Operating Equipment	100
Supplies	400
	$1,600
Estimated Cost per Tonne of Shale	$0.80

Mine Ventilation

The presence of methane gas and the use of diesel equipment will require a large volume of ventilating air. However, much will also depend on the mine layout and system of mining. An average of 4 m^3 of air per minute per tonne of ore mined will probably be required here.

Estimated Cost per Day $350
Estimated Cost per Tonne of Shale..... $0.18

Water Supply

Water will be required for drills, dust and fume suppression, clean-up, and fire control. It is anticipated that much of this requirement will be met from the mine drainage system. Therefore, this cost is included in that item.

Drainage

The oil shale is relatively impervious to water, but the formations above and below may not be so. Therefore, control of mine water will be important. Also, if the shales are siliceous, there will be a tendency to use excessive water for dust suppression, which will increase the drainage requirements.

A potential cause of water inflows will be boreholes drilled from surface to sample the oil shale. These should be cemented when abandoned.

An allowance of $400 per day should be made for the cost of operating the drainage system.

Estimated Cost per Tonne of Shale..... $0.20

Administrative Expenses

This provides for administrative salaries and wages, supplies and services, transportation, and small tools. Included are the general office, engineering office, geologists, safety engineer, external communications, and computer services.

Allowance for General Expenses per Day $2,500
Estimated Cost per Tonne of Shale..... $1.25

Total Operating Costs

All of the above costs are required to deliver shale to the process plant on surface. There is no provision for camp facilities. Labour is assumed to be available locally.

Total Cost per Tonne of Shale Mined	
Development During Production	$ 1.89
Stope Preparation	5.68
Room-and-Pillar Mining	2.27
Load, Haul and Dump	2.00
Conveyor Haulage to Surface	0.16
General Operating Costs	0.80
Mine Ventilation	0.18
Water Supply and Drainage	0.20
Administrative Expenses	1.25
	$14.43

20,000 TONNES PER DAY

Development During Production

In order to maintain production of 20,000 t/d, a major effort will be required to extend the main haulage and ventilation drifts, as well as the cross-cuts, into the production areas.

The annual requirement for this type of opening will be 9,000 m. All of them will be driven in shale; therefore, there is no great advantage in trying to maintain small openings. They will have an area of cross-section of at least 16 m^2.

Estimated Cost per Metre of Advance	
Labour	$340
Operating Equipment	85
Supplies	200
	$625
Estimated Annual Cost	$5,625,000
Estimated Cost per Tonne of Shale	$0.80

Stope Preparation

The geometry of the layout of the rooms-and-pillars and the access to them from the main haulage will depend on the strength of the backs and the attitude of the shale formation. However, the optimum for which to strive will be a nearly square area each year, working on either side of the main haulage. These areas will have to be developed by a series of access cross-cuts for the load–haul–dump units and ventilation.

Each room will be prepared by driving a drift the full height of the room, from one cross-cut to the next. The annual requirement for drifts will be 8,500 m with an area of cross-section of 40 m^2.

Estimated Cost per Metre of Advance	
Labour	$475
Operating Equipment	150
Supplies	300
	$925
Estimated Annual Cost	$7,862,500
Estimated Cost per Tonne of Shale	$1.12

Room-and-Pillar Mining

The development during production and stope preparation will yield a significant tonnage of oil shale.

Estimated Annual Tonnage	
Development	302,400
Stope Preparation	714,000
	1,016,000
Production Required from Rooms; Annual Tonnage	6,000,000
Production Daily Tonnage	17,000
Estimated Cost per Day	
Labour	$11,300
Operating Equipment	6,050
Supplies	15,100
	$32,450
Estimated Cost per Tonne of Shale	$1.91

These figures are based on conventional drill-and-blast breaking. The costs for some form of mechanical cutter would be comparable; powder costs would be eliminated, but costs of electric power would rise to compensate.

Load, Haul and Dump

At this scale of operation, two means of intermediate transport are possible; either the largest load–haul–dump units available or a loader–truck combination might be

considered. In either case, a transfer point or points are necessary to load the broken material for raising to the surface. Here, there will be a grizzly and pneumatic breaker combination to facilitate transport to the surface. The average haulage distance will be 1,000 m.

Estimated Cost per Day	
Labour	$18,900
Operating Equipment	22,700
	$41,600
Estimated Cost per Tonne of Shale	$2.08

Conveyor Haulage to Surface

For the relatively shallow depths of the shale formation, the best method of delivering shale to the plant on surface appears to be by conveyor. During the first 20 years of operation, the average haulage distance will be 5,000 m.

Estimated Cost per Day	
Labour	$2,000
Operating Equipment	200
Supplies	2,600
	$4,800
Estimated Cost per Tonne of Shale	$0.24

General Operating Costs

Costs not directly attributable to specific mining operations are included here. These are such items as communications, sanitation, safety, transportation, housekeeping, fire protection, and electrical.

Estimated Cost per Day	
Labour	$5,600
Operating Equipment	400
Supplies	3,800
	$9,800
Estimated Cost per Tonne of Shale	$0.49

Mine Ventilation

At this scale of operation, very large quantities of ventilating air will be required, especially in the presence of methane gas, diesel fumes and blasting fumes. To achieve economies, unused areas of the mine will have to be isolated and the movement of air very carefully controlled. An estimated requirement for air is 4 m^3 per minute per daily tonne of ore mined, for a total of 80,000 m^3 per minute.

Estimated Cost per Day	
Labour	$ 200
Operating Equipment	500
Supplies	4,500
	$5,200
Estimated Cost per Tonne of Shale	$0.26

Water Supply

The estimated average quantity of water required for underground mining, measured in cubic metres per day, is approximately 0.135 times the tonnes of material mined. The daily cost of this quantity of water for an underground shale mine of 20,000 tonnes would be $400, a negligible amount. As the water would probably be supplied from the mine drainage system, no provision is made here for this cost.

Drainage

At this large scale of underground mining, control of water may be a serious problem. To maintain production and keep costs down, potential aquifers will have to be mined regardless. This means that considerable effort will have to be expended in anticipating aquifers and in controlling their effects.

Large volumes of water may be involved and the possibility of heavy contamination should be anticipated. Therefore, some form of water treatment will be required before it is discharged into the surface drainage system.

An allowance of $4,000 per day should be made for the cost of operating the drainage system.

Estimated Cost per Tonne of Shale..... $0.20

Administrative Expenses

Administrative salaries and wages, engineering office and mine office expenses, external communications, and computer services are provided here. Transportation, small tools and other small items of administrative overhead are included, such as public relations.

Allowance for General Expenses per Day $5,000
Estimated Cost per Tonne of Shale..... $0.25

Total Operating Costs

The above costs are required to deliver shale to the process plant on surface. There is no provision for camp facilities. Labour is assumed to be available at the gate.

Total Cost per Tonne of Shale Mined	
Development During Production	$0.80
Stope Preparation	1.12
Room-and-Pillar Mining	1.91
Load, Haul and Dump	2.08
Conveyor Haulage to Surface	0.24
General Operating Costs	0.49
Mine Ventilation	0.26
Water Supply and Drainage	0.20
Administrative Expenses	0.25
	$7.35

ESTIMATE OF CAPITAL COSTS

The direct capital costs of plant, equipment and preproduction development for working oil shale deposits in Ontario are tabulated below. These are for facilities to mine by surface and underground methods at average daily rates of 2,000 and 20,000 t/d, respectively. The methods are described as in the previous section, Operating Costs.

The estimates are order-of-magnitude only, and they have been derived from the United States Bureau of Mines publication entitled: "Capital and Operating Cost Estimating System Manual for Mining and Beneficiation of Metallic and Nonmetallic Minerals Except Fossil Fuels in the United States and Canada".

The data in this publication are derived from actual mining operations in North America and are considered representative of costs that might be expected for an oil shale operation in Ontario. The costs include contingencies in each case and are probably accurate to within 25% for the criteria set out. All costs are in 1982 Canadian dollars.

SURFACE MINING

2,000 TONNES PER DAY

Preproduction Development		
Clearing (100 hectares)	$ 29,000	
Stripping (3 million tonnes)	3,120,000	$3,149,000
Water and Drainage System		
Water system	$23,000	
Drainage system	5,000	28,000
Communications System		50,000
Fueling System		73,000
Electrical System		37,000
Repair Shops and Warehouses		1,144,000
Offices and Laboratories		166,000

Other Surface Buildings	$ 135,000
Mining Equipment	1,976,000
Engineering and Construction Management Fees	600,000
	$7,358,000

20,000 TONNES PER DAY

These costs are based on the use of walking draglines for handling the overburden, and trucks and shovels for handling the shale. Both the draglines and shovels would be electric-powered.

Preproduction Development		
Clearing (200 hectares)	$ 58,000	
Stripping (20 million tonnes)	15,400,000	$15,458,000
Water and Drainage Systems		
Water system	$25,000	
Drainage system	75,000	100,000
Communications System		125,000
Fueling System (trucks only)		145,000
Electrical System		1,100,000
Repair Shops and Warehouses		4,160,000
Offices and Laboratories		520,000
Other Surface Buildings		312,000
Mining Equipment		38,000,000
Engineering and Construction Management Fees		4,100,000
		$64,020,000

UNDERGROUND MINING

2,000 TONNES PER DAY

These costs are for a room-and-pillar operation using load–haul–dump units and conveyor haulage to surface.

Preproduction Development		
Drifting	$1,456,000	
Decline	1,872,000	
Preparing stopes	4,368,000	$ 7,696,000
Conveying System		624,000
Ventilation System		416,000
Water System		22,000
Drainage System		63,000
Communications System		50,000
Fueling System		14,000
Electrical System		700,000
Repair Shops and Warehouses		416,000
Offices and Laboratories		260,000
Other Surface Buildings		260,000
Mine Equipment		4,576,000
Engineering and Construction Management Fees		3,120,000
		$18,217,000

20,000 TONNES PER DAY

These costs are for a room-and-pillar operation using load–haul–dump units and conveyor haulage to surface.

Preproduction Development		
Drifting	$6,177,000	
Decline	2,059,000	
Preparing stopes	8,486,000	$16,722,000
Conveying System		1,664,000
Ventilation System		1,872,000
Water System		146,000
Drainage System		416,000
Communications System		104,000
Fueling System		42,000
Electrical System		3,120,000
Repair Shops and Warehouses		1,352,000
Offices and Laboratories		832,000

Other Surface Buildings	$ 624,000
Mine Equipment	18,720,000
Engineering and Construction Management Fees	7,280,000
	$52,894,000